

Code Review Programme 2015

Consultation Paper

Submissions close: 5:00 pm on 14 August 2015

30 June 2015

Contents

1.	Introduction and purpose of this paper	1
1.1	Introduction	1
1.2	Purpose of this paper	1
1.3	Submissions	2
2.	Code Review Programme 2015	3
2.1	Background	3
2.2	Format of this paper	4
2.3	How to use this paper	5
3.	Regulatory Statement	9
Appendix A	Format for submissions	11
Appendix B	Proposed Amendments	13
Appendix C	“Minor” amendments	115
Appendix D	Master list of all proposed amendments	196

1. Introduction and purpose of this paper

1.1 Introduction

- 1.1.1 The Electricity Authority (Authority) has developed a list of amendments that it proposes making to the Electricity Industry Participation Code 2010 (Code). The Authority has identified the proposed amendments, which make a variety of improvements to the Code, either in the course of the Authority's work or as the result of suggestions received through the Authority's Code amendment proposal process.¹
- 1.1.2 For the most part, each proposed amendment addresses a discrete issue. Accordingly, the amendments do not (in general) relate to each other. Rather, the amendments mostly represent changes that that it would be beneficial to make, but that do not (of themselves) warrant the resources required for a separate consultation process. We are progressing the amendments together on that basis.
- 1.1.3 The Authority proposes to make the amendments as one "omnibus" Code amendment. The Authority intends to consult on further changes of this type each year. This initiative will be called the annual Code Review Programme.

1.2 Purpose of this paper

- 1.2.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be affected by the proposed amendments.
- 1.2.2 Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and the regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statements relating to each amendment are included in Appendix B of this paper.
- 1.2.3 Please note that due to the nature of the proposed amendments, this consultation paper differs in its format from the consultation papers the Authority usually publishes. Refer to section 2.2: "Format of this paper" below for more information.
- 1.2.4 The Authority invites submissions on the regulatory statements and proposed amendments, including drafting comments.

¹ More information about the Authority's Code amendment proposal process is available at: <http://www.ea.govt.nz/code-and-compliance/the-code/amendments/amending-the-code/>

1.3 Submissions

The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless you are unable to do so electronically. Please email submissions in electronic form to submissions@ea.govt.nz with "Consultation Paper— Code Review Programme 2015" in the subject line.

If submitters do not wish to send their submissions electronically, they should post one hard copy of their submission to either of the addresses provided below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

- 1.3.1 Please ensure we receive your submission by 5:00 pm on Friday, 14 August 2015. Please note that we are unlikely to consider late submissions.
- 1.3.2 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.
- 1.3.3 If possible, please provide your submission in the format shown in Appendix A. We are likely to make your submission available to the general public on the Authority's website. Please indicate any documents attached, in support of your submission, in a covering letter and clearly indicate any information you are providing to the Authority on a confidential basis. However, all information you provide to the Authority is subject to the Official Information Act 1982.

2. Code Review Programme 2015

2.1 Background

- 2.1.1 During the course of its work, the Authority often identifies improvements or clarifications that could be made to the Code. In addition, the Authority invites suggestions for amendments through its Code amendment proposal process.²
- 2.1.2 The Authority includes each amendment that it considers should be made in the Authority's work programme. However, to allocate its resources efficiently, the Authority prioritises some proposals in its work programme over others. This means that the Authority cannot always progress amendment proposals that have merit. In addition, there is a category of amendments that it would be beneficial to make, but that do not of themselves warrant the resources required for a separate consultation process.
- 2.1.3 The Authority proposes to progress a number of these amendments each year as an "omnibus" amendment to the Code. By making a large number of relatively small amendments at once, the Authority considers it will use its resources efficiently, and that the Code will benefit from continual improvement that might not otherwise have been possible. This initiative will be called the annual Code Review Programme.
- 2.1.4 For the 2015 Code Review Programme, the Authority has identified 49 amendments that it proposes to make. Of these, 21 require consultation. In relation to the remaining number, the Authority is satisfied that the amendments meet the requirements of section 39(3) of the Act and therefore do not require consultation (for example, an amendment may be "technical and non-controversial"). However, those amendments are nevertheless included in this paper for information.
- 2.1.5 For the most part, each proposed amendment is discrete from the others, and accordingly this consultation paper relates not to one topic but to many different topics. The table below shows which parts of the Code are affected and the number of clauses in each part that are proposed to be amended:

Part of the Code affected	No. of clauses affected
Part 1 (Interpretation) ³	23

² More information about the Authority's Code amendment proposal process is available at: <http://www.ea.govt.nz/code-and-compliance/the-code/amendments/amending-the-code/>

³ In relation to Part 1, the number of definitions amended has been counted (as well as the addition of a new clause), rather than only the number of clauses affected.

Part 3 (Market operation service providers)	01
Part 6 (Connection of distributed generation)	02
Part 8 (Common quality)	16
Part 9 (Security of supply)	01
Part 10 (Metering)	15
Part 11 (Registry information management)	06
Part 12 (Transport)	14
Part 12A (Distributor use-of-system agreements and distributor tariffs)	12
Part 13 (Trading arrangements)	09
Part 14 (Clearing and settlement)	03
Part 15 (Reconciliation)	13

2.2 Format of this paper

- 2.2.1 As noted above, for the most part, each amendment is discrete from the other in its problem definition and proposed solution. Accordingly, this paper includes a separate analysis for each proposed amendment. This means that this consultation paper necessarily differs in its format from the consultation papers the Authority usually publishes.
- 2.2.2 For each amendment, we have completed a table that sets out the problem definition and the proposed solution (including proposed Code drafting). Each table also contains an assessment of the proposed amendment against the Authority's statutory objective and section 32(1) of the Act, and an assessment of the proposed amendment against the Authority's Code amendment principles.
- 2.2.3 For the 21 amendments that require consultation, the table also contains a regulatory statement. The regulatory statement explains the objectives of the proposed amendment and contains an evaluation of the costs and benefits of the proposed amendment, as well as an evaluation of alternative means for achieving the proposed amendment.
- 2.2.4 In relation to the remaining 28 amendments, the table includes a short explanation of why the Authority has not prepared a regulatory statement and is not formally consulting on the proposed amendment.
- 2.2.5 Each table relating to the 21 amendments on which the Authority is consulting is included in this paper at Appendix B. The tables for the remaining 28 "minor" amendments, on which the Authority is not formally consulting, are included at

Appendix C. In both cases, the tables are set out in Code order – that is, in the order in which the proposed amendments appear in the Code. For example, proposed amendments to Part 1 of the Code are included first. Each table has a unique reference number in its top row.

- 2.2.6 Appendix D is a “master” list showing all of the drafting for all of the proposed Code amendments. Each amendment in the master list is accompanied by the reference number for the table in Appendix B or Appendix C in which the proposed amendment is explained.

2.3 How to use this paper

- 2.3.1 Owing to the large number of topics that this paper covers, the Authority expects that submitters will want to focus only on the proposed amendments that affect them. The lists below set out (in brief) the topics that are addressed by each proposed amendment, along with the reference number for the relevant table in Appendix B or Appendix C.
- 2.3.2 The Authority suggests that submitters use the below lists, as well as the master list of all amendments included in Appendix D, to identify the proposed amendments that are of interest. In this way, submitters should be able to focus their attention on the tables in Appendix B to which they may need to respond.
- 2.3.3 A format for submissions is included in Appendix A.

Amendments on which the Authority is consulting (Appendix B)

Clause(s) affected	Topic	Reference number
1.1(1)	Amending the definition of "contract for differences"	097-001 Page 14
1.1(1)	Replacing the definition of "embedded network"	008-002 Page 20
1.1(1)	Amending the definition of "use-of-system agreement"	084-003 Page 24
3.17, 9.32, 12.97 to 12.99 and 13.231	Removal of auditor obligations	002-004 Page 30
10.25	Requirements for distributors in relation to recertified NSPs that are not points of connection to the grid	020-005 Page 35

10.33	Energising a point of connection that has not previously been energised	022-006 Page 40
10.34	Installation and modification of metering installations	078-007 Page 44
10.37	Measurement of reactive energy on category 2 metering installations	079-008 Page 49
Schedule 10.7, clause 43	Recalibration requirements for installation of category 1 metering installations	087-009 Page 53
11.15C and 14.41 to 14.43	Remedying an event of default	089-010 Page 57
Schedule 11.4, Table 1	Information a metering equipment provider must provide to the registry	046-011 Page 63
12.15	Publication of information about transmission agreements	047-012 Page 71
12.72 to 12.75, and 12.116	Requirement for the Authority to publish a centralised data set	049-013 Page 76
12A.1, 12A.6, and Schedule 12A.1	Revocation of distributor indemnity	093-014 Page 80
12A.4 and 12A.5	Prudential security requirements	050-015 Page 86
12A.14	Electricity Information Exchange Protocols (EIEPs)	051-016 Page 93
15.33	Publication of Code breach reports from the reconciliation manager	069-017 Page 98
15.36	New Zealand Daylight Time adjustment techniques	070-018 Page 101
15.38	Certification of reconciliation participants	071-019 Page 105
Schedule 15.1, clause 6	Publishing lists of certified reconciliation participants	072-020 Page 109
Schedule 15.4, clauses 3, 14	Quantification errors and metering interrogation systems	074-021 Page 112

Amendments the Authority considers to be "minor", in terms of section 39(3) of the Act (Appendix C)

Clause(s) affected	Topic	Reference number
1.1(1)	Amending the definition of "approved test house"	003-022 Page 116
1.1(1)	Amending the definition of "EIEP"	081-023 Page 118
1.1(1)	Replacing the definition of "distributor"	007-024 Page 121
1.1(1)	Amending the definition of "electricity supplied"	083-025 Page 134
1.1(1)	Amending the definitions of "energisation" and "de-energisation"	005-026 Page 136
1.1(1)	Amending the definition of "event date"	009-027 Page 138
1.1(1)	Amending the definition of "metering installation"	082-028 Page 141
1.1(1)	Amending the definition of "special protection scheme"	013-029 Page 143
1.1(1) and 12.27, 12.39, and Schedule 12.2 clause 4	Amending the definition of "value of expected unserved energy" and related clauses	015-030 Page 145
1.1(1) and 13.61, 13.75, and 13.102	Amending the definition of "sub-station dispatch groups" and provisions regarding block security constraints and station security constraints	004-031 Page 148
8.69	Clearing manager to determine wash up amounts payable and receivable	091-032 Page 151
10.17 and Schedule 10.2, clauses 3 and 3A	Audit provision ambiguity	017B-033 Page 153

Schedule 10.6, clause 4	Obligation to keep metering records	024-034 Page 156
Schedule 10.7, clause 19	Modification of metering installations	025-035 Page 158
Schedule 10.7, clause 26	Requirements for certifying metering installations that incorporate meters and data storage devices	027-036 Page 161
Schedule 10.7, clause 45	Category 1 metering installation inspection requirements	028-037 Page 165
11.11, 15.37 and Schedule 15.1, clause 12 and 12A	Audit provision ambiguity	017A-038 Page 168
Schedule 11.3, clause 3	Approval of valid switch response code	041-039 Page 171
Schedule 11.4, Table 1	Registry metering records: settlement indicator	045A-040 Page 173
12A.2, 12A.3, 12A.7, 12A.13	Revocation of redundant transitional provisions from Part 12A	094-041 Page 175
13.101	Publication of report relating to a grid emergency	056-042 Page 179
13.114 and 13.118	Exchanging information that relates to auctions through the information system	057-043 Page 181
13.236A	Spot price risk disclosure statements	059-044 Page 183
Schedule 13.8, clause 2	Application for approval for a dispatch-capable load station	061-045 Page 185
15.5A and 15.5B	Preparation of dispatchable load information by dispatchable load purchasers	064-046 Page 187
15.38	Functions requiring certification - provision of metering information to grid owner	095-047 Page 190
15.38	Functions requiring certification: subclause (1)(d), (da), and (db)	096-048 Page 192
Schedule 15.3, clause 9	Rounding of submission information	076-049 Page 194

3. Regulatory Statement

- 3.1.1 As noted above, this consultation paper differs in its format from the consultation papers the Authority usually publishes (refer to section 2.2 above: "Format of this paper"). For each proposed amendment that requires a regulatory statement, the statement is included in the relevant table for the proposed amendment in Appendix B.
- 3.1.2 The primary economic benefit described in the regulatory statements is a reduction in transaction costs across the industry, which is a productive efficiency benefit. The costs for the Authority and participants are largely either zero or negligible, as in many cases the amendments are removing unnecessary obligations or aligning the Code with industry practice.
- 3.1.3 When assessing the benefits and costs of Code amendment proposals, the Authority typically uses a real discount rate of 6% with sensitivities of plus or minus 2%. For the Code Review Programme 2015, the Authority has used a point estimate of the discount rate, for ease of analysis. To minimise the risk of overstating the net benefit of a proposal, the Authority has used a real discount rate of 8%.

Appendix A Format for submissions

Please complete the table below for each proposed amendment on which you wish to submit. Please ensure that you include the reference number for the relevant table in Appendix B (refer to the first row of the table in Appendix B that contains the amendment on which you are submitting).

Reference number for amendment you are submitting on:	
Question 1: Do you agree with the Authority's problem definition? If not, please provide comments.	
Question 2: Do you agree with the Authority's proposed solution? If not, please provide comments.	
Question 3: Do you have any comments on the Authority's proposed Code drafting?	

Question 4: Do you agree with the objectives of the proposed amendment? If not, why not?

Question 5: Do you agree the benefits of the proposed amendment outweigh its costs?

Question 6: Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Appendix B Proposed Amendments

Disclosure of exchange-traded futures contracts below 0.25 MW

Reference number(s)	097-001
Issue	<p>Subpart 5 of Part 13 of the Code requires the public disclosure of information about risk management contracts that participants have entered into, including contracts for differences (CfDs). Participants are not required to disclose information about CfDs covering a quantity of less than 0.25 MW.</p> <p>At present, NZ electricity futures on the ASX are traded in units of 1 MW. However ASX plans to reduce the unit size to 0.1 MW.</p> <p>If status quo arrangements are still in force after ASX reduces the unit size to 0.1 MW, then futures trades below 0.25 MW will not need to be disclosed to the Authority. If these trades are not disclosed, then it will not be possible to monitor trading in the NZ futures market effectively, or to make comparisons between NZ electricity futures and other risk management products.</p> <p>The Authority plans to carry out a fundamental review of the hedge disclosure requirements in the Code. However, that review will be some time away. In the interim, the Authority seeks to ensure that it is able to effectively monitor trading in the NZ futures market.</p>
Proposal	<p>The proposed Code amendment would require participants to disclose all trades in exchange-traded electricity futures, irrespective of the size of the trade.</p> <p>For the avoidance of doubt, the proposed Code amendment retains the current requirement on participants to disclose non-exchange-traded electricity futures equal to or exceeding 0.25 MW of electricity.</p>
Proposed Code amendment	<p>Amend the definition of contract for differences as follows:</p> <p>contract for differences, for the purposes of subpart 5 of Part 13, means a financial derivative contract—</p> <ul style="list-style-type: none"> (a) under which 1 or both parties makes or may make a payment to the other party; and (b) in which the payment to be made depends on, or is derived from, the price of a specified quantity of electricity at a particular time; and (c) that may provide a means for the risk to 1 or both parties of an increase or decrease in the price of electricity to be reduced or eliminated; and

	<p>(d) in which that either—</p> <p>(i) the relates to a quantity of electricity that the contract relates to equals or exceeds 0.25 MW of electricity; or</p> <p>(ii) is entered into through a derivatives exchange, being a market in which parties trade standardised financial derivative contracts, and contracts containing the right to buy or sell standardised financial derivative contracts, with a central counterparty</p>
<p>Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act</p>	<p>The proposed amendment is consistent with the Authority's statutory objective because it is expected to contribute to a well-functioning hedge market, by:</p> <ul style="list-style-type: none"> • providing data to inform future regulation of the hedge market • providing participants with hedge market data. <p>A well-functioning hedge market promotes:</p> <ul style="list-style-type: none"> • wholesale and retail competition, by providing participants with a means to manage wholesale market risk • efficiency, by informing participants' investment and operational decision making. <p>Accordingly, the amendment is also desirable to promote competition in, and the efficient operation of, the electricity industry in accordance with section 32(1)(a) and 32(1)(c) of the Act.</p> <p>Further, the amendment is desirable to promote the performance by the Authority of its function of undertaking market monitoring, in accordance with section 32(1)(d) of the Act. In order to be able to monitor the ASX NZ futures market effectively, the Authority needs to be able to obtain information about futures trades.</p> <p>The amendment is not expected to affect reliability.</p>
<p>Assessment against Code amendment principles</p>	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
<p>Principle 1: Lawfulness.</p>	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32 of the Act.</p>
<p>Principle 2: Clearly</p>	<p>The proposed amendment is consistent with principle 2 in that it</p>

Identified Efficiency Gain or Market or Regulatory Failure	addresses a problem created by the existing Code (i.e. that futures trades under 0.25 MW need not be disclosed), which requires an amendment to resolve.							
Principle 3: Quantitative Assessment	A quantitative assessment of the proposal's costs and benefits has been undertaken (see below).							
Regulatory Statement								
Objectives of the proposed amendment	The objective of the proposal is to require participants to disclose all trades in exchange-traded electricity futures, irrespective of the size of the trade.							
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the expected net benefit of the proposal is positive, for the reasons set out below.</p> <p>The main cost of the proposal would be that it would require participants to spend time on disclosing futures trades of 0.1 MW or 0.2 MW. The economic cost of such disclosure is estimated at \$0.1 million present value (over five years, using an 8% real discount rate), on the assumption that:</p> <ul style="list-style-type: none"> • 10,000 futures trades below 1 MW would be disclosed in each year (<i>for reference, about 5,300 futures trades of 1 MW were disclosed in the 2014 calendar year</i>) • 20% of these trades would be disclosed manually (<i>c.f. through an automated process, as currently used by the main participants trading on the ASX</i>) • manually disclosing a futures trade takes, on average, 10 minutes of trader time (<i>while automated disclosure has no incremental cost</i>) • the cost of trader time is \$130,000 per year, or \$12 per 10 minutes. <p><i>(The cost is calculated over five years because the Authority anticipates that some kind of automated data feed – either from ASX to the Authority, or from participants to the Authority – will replace the current manual process in the longer term.)</i></p> <p>Key sensitivities are shown below.</p> <table border="1"> <thead> <tr> <th>Assumption</th><th>Value</th><th>Estimated economic cost (\$ million present value)</th></tr> </thead> <tbody> <tr> <td></td><td></td><td></td></tr> </tbody> </table>		Assumption	Value	Estimated economic cost (\$ million present value)			
Assumption	Value	Estimated economic cost (\$ million present value)						

	Number of futures trades below 1 MW disclosed, per year	5,000	0.05
		20,000	0.21
	Average time to disclose	5 minutes	0.05
		20 minutes	0.21
	Proportion of trades disclosed manually	10%	0.05
		30%	0.16

Across all the sensitivities considered, the estimated economic cost varies between \$0.05 million and \$0.21 million present value.

The main **benefit** of the proposal is that it would support a better-functioning hedge market.

The proposal would provide the Authority with data about all sizes of futures trades – including the parties that are trading, and the prices, quantities and times of each small trade in each product. Without the proposed change, there is a risk that some parties may cease logging any futures transactions on the basis that each contract is for less than 0.25MW. This data would be used by the Authority to construct hedge market metrics – with a focus on participation by new entrants to the ASX NZ market, and on the performance of market makers. These hedge market metrics would support the Authority's analysis of hedge market issues, and would assist the Authority to carry out good quality regulation of the hedge market.

Further, the proposal would provide participants with better information about small futures trades – both through the hedge disclosure website, and through information provided by third party providers of market analysis and commentary. Such information would assist participants to compare different types of risk management arrangements, and would support participant decision making.

The primary benefits of a well-functioning hedge market are that it

- promotes retail competition – which, in turn:
 - promotes innovation in retail offerings
 - puts downward pressure on retail cost-to-serve
 - helps to ensure that industry efficiency gains are passed on to consumers
- promotes efficient investment in, and operation of, generation and demand response.

Total retail cost-to-serve is approximately \$400 million dollars per

	<p>year (estimated as \$200 per year for each of about two million mass-market consumers). Total generation cost is approximately \$1 billion dollars per year (estimated as fuel costs of \$50/MWh across 10 TWh of annual output, plus operations and maintenance costs of \$5/MWh across 40 TWh of annual output, plus the capital cost of new generation to serve a 1% annual increase in peak demand at \$4,000/kW).</p> <p>If the proposal resulted in a reduction in retail cost-to-serve by at least 0.01% and a reduction in generation costs by at least 0.002%, then the economic benefit over five years would be at least \$0.26 million present value (using an 8% real discount rate) – which would exceed the estimated economic cost.</p> <p>The Authority considers that it is very likely that the proposal would achieve at least the above level of economic benefit because it will ensure that data continues to be available to inform future regulation of the hedge market, and it will continue to provide participants with hedge market data. Therefore, the Authority concludes that the expected net economic benefit of the proposal is positive.</p>
<p>Evaluation of alternative means of achieving the objectives of the proposed amendment</p>	<p>The Authority could require participants to provide information on futures contracts under 0.25 MW using its powers under section 46 of the Electricity Industry Act 2010. This would achieve the same effect as the proposal, but would be more costly and onerous for all involved. Further, using these powers for a foreseeable and ongoing purpose would set a bad precedent that should be avoided.</p>
	<p>The Authority could obtain ASX futures and options data either from the information published by ASX, or through a data vendor. However, such data would not contain identifying information – i.e. the Authority would not be able to determine which participant was involved in each trade. This would mean that the data would be of limited use for the Authority’s purposes. For instance, the data would not be helpful in assessing market maker performance.</p>
	<p>In future, it may be possible for the Authority to obtain futures and options data directly from ASX, in a form that includes identifying information. This would remove the need for individual participants to disclose futures contracts. However, the Authority understands that ASX is not currently able to provide such data, and will not be able to do so until it has carried out an IT system upgrade later in 2015. Nor has ASX consented to provide such data.</p>

	<p>The Authority could extend the disclosure regime to include all CfDs – which would also capture over-the-counter (OTC) contracts of less than 0.25 MW. However, in the Authority’s view, the costs of providing information about OTC CfDs under 0.25 MW would exceed the benefits.</p>
--	--

Definition of “embedded network”: clause 1.1(1)

Reference number(s)	008-002
Issue	<p>The definition of embedded network in Part 1 states that an embedded network means:</p> <p>... a system of lines, substations and other works used primarily for the conveyance of electricity between two points (point A and point B), where—</p> <ul style="list-style-type: none"> (a) point A is a point of connection between a local network or another embedded network; and (b) point B is a point of connection between a consumer, an embedded generating station, or both; and (c) the electricity flow at point A is quantified by a metering installation in accordance with Part 10 <p>This definition creates a number of issues.</p> <p>First, the word “between” in paragraphs (a) and (b) is confusing. Paragraph (a) refers to a point of connection between a local network or another embedded network, but does not specify what is being connected to the local or embedded network via that point of connection. Similarly, paragraph (b) refers to a point of connection between a consumer, embedded generating station, or both, but does not specify what is being connected to the consumer or the embedded generating station via that point of connection.</p> <p>The Authority also considers it confusing and undesirable to define an embedded network by reference to a point of connection. Instead, the definition of embedded network need only make it clear that an embedded network is a system of lines, substations, and other works used primarily for the conveyance of electricity that is connected to the grid only through 1 or more other networks (ie it is not directly connected to the grid).</p> <p>In addition, it is not necessary to refer specifically to consumers or embedded generating stations. Instead, the definition should specify that for a network to be an embedded network, it must have 1 or more ICPs directly connected to it.</p> <p>The Authority also considers that it is unnecessary to refer to electricity flow being quantified by a metering installation in accordance with Part 10, as other provisions in the Code specify requirements relating to metering installations at an ICP.</p>

Proposal	The proposal is to replace the definition of embedded network.
Proposed Code amendment	<p>Replace the definition of embedded network with the following definition:</p> <p><u>embedded network</u> means a system of lines, substations and other works, used primarily for the conveyance of electricity, that—</p> <p>(a) <u>is connected to the grid only through 1 or more other networks; and</u></p> <p>(b) <u>has 1 or more ICP identifiers recorded in the registry as being connected to it</u></p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definition in the manner proposed would reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this amendment. Accordingly, a quantitative analysis has not been undertaken.</p> <p>Please refer to the qualitative cost-benefit analysis under the Regulatory Statement below.</p>

Regulatory Statement	
Objectives of the proposed amendment	<p>The objectives of the proposal are to:</p> <ul style="list-style-type: none"> (a) correct the definition of embedded network, as it currently does not make sense (b) clarify what an embedded network is so as to avoid confusion.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority does not expect the proposed amendment to place additional costs on industry participants. However, if it did, these would be negligible.</p> <p><u>Benefits</u></p> <p>The benefit from implementing the proposed amendment would be the avoided cost of consumer networks setting themselves up as embedded networks, in order to comply with the Code, when this was not the intended purpose of the Code provision.</p> <p>The cost for a consumer network to do this may be as high as several tens of thousands of dollars, depending on the size of the consumer network. Activities required to become an embedded network would include establishing installation control points (ICPs), negotiating use-of-system agreements, and installing consumer metering for each ICP.</p> <p>The incremental cost for a retailer to set up and maintain an embedded network in its systems (compared to a consumer network) is estimated to be several thousands of dollars. Activities required include setting up the embedded network's tariffs in the retailer's billing system and developing new invoice templates (eg, that have a phone number for network faults which is specific to the embedded network).</p> <p><u>Net benefit</u></p> <p>To the extent that it avoids the unnecessary establishment of one embedded network, the proposed amendment would have a positive net benefit. The Authority considers there is a reasonable likelihood of this occurring, and so therefore considers the proposal has a positive net benefit.</p>

Evaluation of alternative means of achieving the objectives of the proposed amendment	The only option would be to retain the status quo, which would not achieve the objectives of the proposed amendment.
---	--

Amendment to definition of "use-of-system agreement" to include embedded networks: clause 1.1(1)

Reference number(s)	084-003
Issue	<p>The definition of "use-of-system agreement" in Part 1 of the Code provides that a "use-of-system agreement" is an agreement between a distributor and a trader, which allows the trader to trade on the distributor's local network.</p> <p>The Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Amendment 2011 added the definition of "use-of-system agreement" to the Code at the same time as it added Part 12A to the Code. Part 12A includes a number of provisions relating to use-of-system agreements. It was intended that those provisions should apply to distributors and traders who enter into a use-of-system agreement in respect of a local network or an embedded network.</p> <p>However, the definition of "use-of-system agreement" inadvertently omitted reference to embedded networks. Accordingly, the provisions relating to use-of-system agreements in Part 12A do not apply in respect of agreements with distributors who are embedded network owners, even though that was intended.</p> <p>Apart from Parts 1 and 12A of the Code, the term 'use-of-system agreement' is only used in one other place in the Code. Clause 14.41 sets out a list of events that constitute an 'event of default'.</p> <p>One of the events listed (in paragraph (h)) is the termination of a trader's use-of-system agreement with a distributor because of a serious financial breach, provided that specified circumstances apply.</p> <p>One of the specified circumstances is that the "trader continues to have a customer or customers on the distributor's local network". To be consistent with the proposed amendment to the definition of 'use-of-system agreement', this should also refer to the trader continuing to have a customer or customers on the distributor's embedded network.</p>
Proposal	Amend the definition of "use-of-system agreement" so that it also includes an agreement that allows a trader to trade on a distributor's embedded network.

	<p>Make consequential amendments to clause 14.41 to ensure that paragraph (h) applies to a use-of-system agreement in relation to an embedded network, as well as in relation to a local network.</p>
Proposed Code amendment	<p>use-of-system agreement means an agreement between a distributor and a trader that allows the trader to trade on the distributor's local network <u>or embedded network</u></p> <p>14.41 Definition of an event of default Each of the following events constitutes an event of default:</p> <p>...</p> <p>(h) termination of a trader's use-of-system agreement with a distributor because of a serious financial breach if—</p> <p>(i) the trader continues to have a customer or customers on the distributor's local network <u>or embedded network</u>; and</p> <p>(ii) there are no unresolved disputes between the trader and the distributor in relation to the termination; and</p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the promotion of competition in and the efficient operation of the electricity industry.</p> <p>The proposed amendment will do that by ensuring that the provisions in Part 12A, which place obligations on distributors in respect of use-of-system agreements, also apply to distributors that are embedded network owners, as was always intended. The proposed amendment would make it easier to standardise distributor arrangements and lower potential barriers to retail entry on a network (local or embedded).</p> <p>The proposed amendment would also mean that if a trader's use-of-system agreement with a distributor is terminated because of a serious financial breach, the termination could constitute an event of default if the trader continues to have a customer or customers on the distributor's embedded network.</p> <p>At present, this is only the case if the trader continues to have a customer or customers on the distributor's local network (and if the other specified circumstances apply).</p> <p>Accordingly, the proposed amendment is desirable to promote competition in the electricity industry in accordance with section 32(1)(a) of the Act, and the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p>

	The proposed amendment would have no effect on reliability.
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	Refer to the qualitative cost benefit analysis under the Regulatory Statement section below.
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to allow the provisions relating to use-of-system agreements in Part 12A, and the reference in Part 14, to apply in respect of agreements with distributors who are embedded network owners.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The non-discretionary incremental costs on embedded network owners that would be directly attributable to the proposed amendment are:</p> <ul style="list-style-type: none"> the requirement to negotiate the terms of a use-of-system agreement (including any amendment) in good faith the requirement to follow the mediation procedures in clause 12A.3 of the Code in regard to negotiating use-of-system

	<p>agreements</p> <ul style="list-style-type: none"> the requirement to include, in use-of-system agreements, the indemnity set out in schedule 12A.1 of the Code.⁴ <p>The obligation to include in use-of-system agreements the indemnity set out in Schedule 12A.1 duplicates the equivalent provisions in the Consumer Guarantees Act 1993. Therefore the Authority does not consider this to be a cost that would be imposed on embedded networks under the proposed amendment.⁵</p> <p>Retailers may face some costs implementing the proposed amendment to Part 14 (amending their contracts with embedded network consumers to give effect to the trader default provisions in the Code). However, these implementation costs are expected to be negligible, possibly non-existent. This is on the basis that retailers use the same contracts for consumers on embedded networks as for consumers on local networks and retailers have amended their retail contracts to meet the requirements of Part 14 of the Code.</p> <p>Traders and embedded network owners would be expected to face some incremental costs under the proposal if an event of default were to occur.</p> <p><u><i>Benefits</i></u></p> <p>The first key benefit of the proposed amendment is the reduced cost (time and effort) faced by retailers and embedded network owners negotiating use-of-system agreements. The Authority estimates the proposal could reduce the combined transaction costs of retailers and embedded network owners entering into a use-of-system agreement by several thousand dollars. Given the steady increase in embedded networks in New Zealand,⁶ this potential saving in transaction costs each time a new use-of-system agreement is negotiated would be material.</p> <p>The reduced negotiating effort and associated cost saving should represent a material reduction in the cost for retailers to serve consumers on embedded networks. This is because of the relatively small number of consumers that typically are on embedded networks. The reduced cost-to-serve should encourage greater</p>
--	--

⁴ While the proposed amendment would impose obligations on embedded network owners in relation to prudential requirements, the Authority considers these would be negligible (in the case of clause 12A.4) or they would be at the embedded network owner's discretion (in the case of 12A.5).

⁵ In fact the Authority is proposing that this obligation be removed from the Code, since it duplicates an equivalent provision in the Consumer Guarantees Act.

⁶ From 88 in 2009 to 149 in 2014.

	<p>competition amongst retailers on embedded networks. This is the second key benefit of the proposed Code amendment.</p> <p>The proposed Code amendment's third key area of benefit is the reduced cost should such an event of default occur. Consumers would benefit from:</p> <ul style="list-style-type: none"> • removing the risk of disconnection by the embedded network owner in the event of a retailer default • the lowering of barriers to competition.⁷ <p>In addition to these key benefits, there would be administrative and other cost savings for the industry and the Authority in managing an unresolved event of default within a known structure. Retaining the status quo risks an ad hoc response to an event of default, developed under urgency.⁸</p> <p><u><i>Net benefit</i></u></p> <p>The Authority considers that the net benefit of the proposed amendment is positive.</p> <p>In regard to the provisions in Part 12A that are affected by the proposed amendment, the Authority considers that the economic benefits from lower transaction costs and the greater incentive on retailers to compete on embedded networks would outweigh any potential costs to embedded network owners.</p> <p>To the extent that embedded network owners face costs under the proposal, these are more likely to be wealth transfers to retailers than examples of economic dis-benefits (eg, the mediation process resulting in the embedded network owner taking on an obligation that it wanted the retailer to perform).</p> <p>In regard to the provisions in Part 14 that are affected by the proposed amendment, the Authority considers that the efficiency and competition benefits would exceed the upfront implementation costs and the operational costs that would arise if an event of default occurred.</p>
--	---

⁷ Refer to the Authority's 2013 consultation paper entitled 'Arrangements to manage a retailer default situation', available on the Authority's website at www.ea.govt.nz/dmsdocument/15140.

⁸ *Ibid.*

Evaluation of alternative means of achieving the objectives of the proposed amendment	The only alternative would be the status quo which would not achieve the objectives of the proposed amendment.
---	--

Removal of auditor obligations: clauses 3.17, 9.32, 12.97 to 12.99, and 13.231

Reference number(s)	002-004
Issue	<p>Clauses 3.17, 9.32, 12.97 to 12.99, and 13.231 place reporting obligations on auditors. The Act only permits the Authority to place obligations on industry participants, persons acting on behalf of industry participants and the Authority.</p> <p>Auditors are not industry participants under the Act. Also, it is not clear that auditors are acting on behalf of industry participants when providing audits required by the Code or by the Authority, albeit that the audits are of industry participants. Accordingly, it is better that the Code only places obligations on industry participants in relation to their audits.</p>
Proposal	<p>The proposal is to amend clauses 3.17, 9.32, 12.97 to 12.99, and 13.231:</p> <ul style="list-style-type: none"> to remove the obligation contained in each of those clauses from the auditor to instead require the relevant participant to ensure that the auditor takes certain steps and that the audit report complies with certain requirements.
Proposed Code amendment	<p>3.17 Market operation service provider must arrange audit of software</p> <p>(1) Unless otherwise agreed by the Authority in writing, each market operation service provider must arrange and pay for a suitably qualified independent person approved by the Authority to carry out—</p> <ol style="list-style-type: none"> before any software is first used by the market operation service provider in connection with this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the Act, an audit of all software and software specifications to be used by the market operation service provider; and an annual audit of all software used by the market operation service provider, within 1 month after 1 March in each year; and an audit of any changes to the software or the software specification, before it is used by the market operation

	<p>service provider.</p> <p>(2) <u>A market operation service provider must ensure that the person carrying out an audit under subclause (1) provides a</u> The auditor must report to the Authority as to—</p> <p>(a) the performance (including likely future performance) of all of the software in accordance with the relevant software specification; and</p> <p>(b) any other matters that the Authority requires.</p> <p>...</p> <p>9.32 Auditor must provide audit report</p> <p>(1) The retailer must ensure that the auditor must provides the Authority with an audit report on the retailer's compliance with this subpart <u>that has been prepared in accordance with this clause.</u></p> <p>(2) <u>The audit report must include any comments from the retailer on any non-compliance found by the auditor if the retailer provided the comments to the auditor within a time specified by the auditor.</u> Before the auditor provides the audit report to the Authority, the auditor must refer any non-compliance to the retailer for comment. The retailer must provide comments within a time specified by the auditor.</p> <p>(3) The auditor must include the retailer's comments, if any, in the audit report.</p> <p>(4) <u>The audit report must not contain</u> The auditor must not provide the Authority with a copy of any of the information provided by the retailer to the auditor under clause 9.31 unless requested by the Authority.</p> <p>...</p> <p>12.97 Audit of transmission prices</p> <p>(1) The Authority may appoint an auditor to confirm whether Transpower's transmission prices have been calculated in accordance with the transmission pricing methodology.</p> <p>(2) <u>Transpower must ensure that the</u> The auditor's report must consider <u>includes the auditor's view on</u> whether the application of the transmission pricing methodology by Transpower contains errors or inconsistencies that may have a material impact on the prices of any individual designated transmission customers, or designated transmission customers in general.</p> <p>(3) Transpower must provide the auditor with all relevant information required by the auditor to complete its review.</p> <p>12.98 Transpower may respond to auditor's report</p> <p><u>Transpower must ensure that the auditor's report includes any comments that Transpower provided to the auditor be</u></p>
--	---

	<p>provided with the opportunity to respond in writing to the auditor's report within 15 business days of Transpower receiving the <u>a draft of the report</u>, before the finalization of the audit report.</p> <p>12.99 Final auditor report to the Authority</p> <p>(1) Transpower must ensure that, within Within 10 business days after the auditor receives receipt of Transpower's response under clause 12.98, the auditor must provides a report to the Authority certifying that either—</p> <p>(a) Transpower had applied correctly the approved transmission pricing methodology; or</p> <p>(b) material errors remained in the application by Transpower of the transmission pricing methodology.</p> <p>(2) Within 5 business days of receiving the report, the Authority must publish the auditor's report.</p> <p>...</p> <p>13.231 Audit of information</p> <p>(1) The Authority may, in its discretion, carry out an audit as to whether a participant has complied with this subpart.</p> <p>(2) If the Authority decides under subclause (1) that a participant should be subject to an audit, the Authority must first require the participant to nominate an appropriate auditor. The participant must provide that nomination within a reasonable timeframe. The Authority must appoint the auditor nominated by the participant. If the participant fails to nominate an appropriate auditor within a reasonable timeframe, the Authority may appoint an auditor of its own choice.</p> <p>(3) A participant subject to an audit under this clause must, on request from the auditor, provide the auditor with a copy of every risk management contract that it has entered into in the previous 12 months or within such other period specified by the auditor. The participant must provide this audit information no later than 20 business days after receiving a request from the auditor for the information.</p> <p>(4) The participant must ensure that the auditor provides the Authority with must produce an audit report on the participant's compliance with this subpart <u>that has been prepared in accordance with subclauses (5) and (6)</u>. Before the audit report is submitted to the Authority, any non-compliance must be referred back to the participant for comment. The comments of the participant must be included in the audit report.</p> <p>(4A) The audit report must include any comments from the participant on any non-compliance found by the auditor if the</p>
--	--

	<p><u>participant provided comments to the auditor within a time specified by the auditor.</u></p> <p>(5) <u>The audit report must not contain</u> The auditor must not provide the Authority with a copy of any risk management contract that the participant has provided to the auditor in accordance with subclause (3), unless the Authority has specifically requested that the auditor do so.</p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Stating the obligations in the manner proposed would clarify the obligation on industry participants being audited to ensure their auditors meet the audit requirements.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32 of the Act. The proposed amendment also seeks to remove potentially unlawful aspects of the Code.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a qualitative assessment has been undertaken (see below).</p>
Regulatory Statement	

Objectives of the proposed amendment	The objective of the proposal is to amend the relevant provisions to give industry participants being audited a clear incentive to ensure their auditors are meeting audit requirements.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment would place no additional costs on industry participants. However, if it did, these costs would be negligible.</p> <p>This is because the proposed drafting reflects current industry practice. Participants already ensure that auditors comply with the required steps in the Code when carrying out audits.</p> <p><u>Benefits</u></p> <p>The primary benefit from implementing the proposed amendment would be improved clarity for industry participants being audited that they are responsible for ensuring their auditors meet the relevant audit requirements set out in the Code. This would reduce compliance costs for new entrant participants and the Authority's costs educating participants on the intent of the clauses that incorrectly place the obligations on auditors, who are not industry participants.</p> <p><u>Net benefit</u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	The only alternative to the proposal is the status quo. If this option were pursued, the benefits outlined above would not eventuate. Accordingly, the Authority is satisfied that the proposal is the best alternative.

Metering installation certification expiry dates: clause 10.25

Reference number(s)	020-005
Issue	<p>Clause 10.25 relates to the obligations on distributors in relation to network supply points (NSPs) that are not points of connection to the grid, including the responsibility for ensuring that there is a metering installation installed at such NSPs.</p> <p>Subclause (2) sets out the requirements that a distributor must comply with if the distributor proposes to create a new NSP that is not a point of connection to the grid. Under clause 10.25(2)(c), the distributor must advise the reconciliation participant for the NSP of the certification expiry date of each metering installation for the NSP no later than 20 business days after each metering installation is certified.</p> <p>Clause 10.25(2)(c) contains an error as it requires the distributor to advise the “reconciliation participant for the NSP” of each metering installation’s certification expiry date. The distributor should advise the reconciliation manager, not the reconciliation participant for the NSP.</p> <p>In addition, paragraphs (b) and (c) of clause 10.25(2) only apply when a distributor proposes to create a <i>new</i> NSP that is not a point of connection to the grid. The intention was for distributors to also comply with those requirements when a metering installation for an <i>existing</i> NSP that is not a point of connection is recertified.</p> <p>Finally, subclause (1)(b) contains a punctuation error, and it could be clarified that the requirement in subclause (2)(b) relates to the relevant metering installation.</p>
Proposal	<p>The proposal is to:</p> <ul style="list-style-type: none"> (a) fix the punctuation error in subclause (1)(b) and clarify that the requirement in subclause (2)(b) relates to the relevant metering installation (b) amend clause 10.25(2)(c) to correct the error referred to above – “reconciliation participant for the NSP” will be replaced with “reconciliation manager” (c) add a new subclause (3) to the clause that requires distributors to advise the reconciliation manager of the following information when a metering installation for an existing NSP that is not a point of connection is recertified:

	<ul style="list-style-type: none"> (i) the reconciliation participant for the NSP (ii) the participant identifier of the metering equipment provider (iii) the certification expiry date of the metering installation.
Proposed Code amendment	<p>10.25 Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid</p> <p>(1) A distributor must, for each NSP that is not a point of connection to the grid, and for which it is recorded in the NSP table on the Authority's website as being responsible, ensure that—</p> <ul style="list-style-type: none"> (a) there is 1 or more metering installations; and (b) all electricity conveyed is quantified in accordance with this Code. <p>(2) A distributor must, if it proposes the creation of a new NSP that is not a point of connection to the grid,—</p> <ul style="list-style-type: none"> (a) for each metering installation for the NSP, either— <ul style="list-style-type: none"> (i) assume responsibility for being the metering equipment provider; or (ii) contract with a person who, in that contract, assumes responsibility for being the metering equipment provider; and (b) no later than 20 business days after assuming responsibility or entering into the contract under paragraph (a), advise the reconciliation manager of— <ul style="list-style-type: none"> (i) the reconciliation participant for the NSP; and (ii) the participant identifier of the metering equipment provider <u>for the metering installation</u>; and (c) no later than 20 business days after the date of certification of each metering installation, advise the reconciliation manager reconciliation participant for the NSP of the certification expiry date of the metering installation. <p>(3) In relation to an NSP of the type described in subclause (1), a distributor must, no later than 20 business days after a metering installation for such an NSP is recertified, advise the reconciliation manager of the following:</p> <ul style="list-style-type: none"> (a) <u>the reconciliation participant for the NSP:</u> (b) <u>the participant identifier of the metering equipment provider for the metering installation:</u> (c) <u>the certification expiry date of the metering</u>

	<u>installation.</u>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Ensuring that the reconciliation manager has information about recertified NSPs that are not points of connection means that the information is also available to the Authority. The Authority uses the information (obtained from the reconciliation manager) to populate and publish the NSP table (under clause 10.49). The information in the NSP table enables the Authority to monitor metering certification, which improves operational efficiency and minimises the risk that some metering installations operate when uncertified. Ensuring that all metering installations are certified contributes to accurate recording of electricity consumption and allocation of electricity market costs.</p> <p>In relation to section 32(1)(c) of the Act, the proposed amendment is desirable to promote the efficient operation of the electricity industry.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this amendment. Accordingly, a qualitative assessment has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed	<p>The objectives of the proposal are to:</p> <p>(a) improve the efficient operation of the electricity industry by</p>

amendment	<p>ensuring that the reconciliation manager has information about recertified NSPs that are not points of connection, which in turn enables the Authority to monitor metering certification</p> <p>(b) resolve minor drafting errors in clause 10.25.</p>
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants. However, if it did, they would be negligible.</p> <p>This is because distributors already provide the reconciliation manager with information about recertified metering installations at NSPs that are not points of connection. The proposed drafting reflects current industry practice.</p> <p><u>Benefits</u></p> <p>The primary benefit from implementing the proposed amendment would be reduced compliance monitoring costs for the Authority. The proposal would also reduce the reconciliation manager's transaction costs by enabling it to more easily ascertain who the responsible party is for recertified NSPs that are not a point of connection.</p> <p>Ensuring that the reconciliation manager has information about recertified NSPs that are not points of connection means that the information is also available to the Authority. The Authority uses the information (obtained from the reconciliation manager) to populate and publish the NSP table (under clause 10.49). The information in the NSP table enables the Authority to monitor metering certification, which reduces the risk that some metering installations operate when uncertified. Ensuring that all metering installations are certified contributes to accurate recording of electricity consumption and allocation of electricity market costs.</p> <p><u>Net benefit</u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed	<p>The only alternative to the proposal is the status quo. The risk associated with the status quo is that distributors may not provide the reconciliation manager with information about recertified metering installations at NSPs that are not points of connection (including</p>

amendment	<p>because distributors may not realise that they need to).</p> <p>Accordingly, the Authority is satisfied that the proposed amendment is the best alternative.</p>
-----------	---

Energisation of a point of connection: clause 10.33(1)(c)

Reference number(s)	022-006
Issue	<p>Clause 10.33(1)(c) only allows a reconciliation participant to energise a point of connection, or authorise a point of connection to be energised, if (along with other conditions) the owner of the network to which the point of connection is connected has given written approval. However, a reconciliation participant should only need to obtain the network owner's approval in the case of new connections. This would allow the network owner to ensure that safety requirements are met before a connection is energised, without imposing undue costs on the parties in the case of re-energising connections that have previously been energised.</p> <p>If a connection has previously been energised, the reconciliation participant should not need to re-obtain the network owner's approval. Clause 10.33(3) addresses the issue of safety when re-energising connections.</p>
Proposal	<p>The proposal is to amend clause 10.33(1)(c) so that it only applies to new connections (that is, ICPs being energised for the first time).</p> <p>Subclauses (2) to (4) would not be amended but are set out below for reference.</p>
Proposed Code amendment	<p>10.33 Energisation of point of connection</p> <p>(1) A reconciliation participant may energise a point of connection, or authorise a point of connection to be energised, if—</p> <ul style="list-style-type: none"> (a) the reconciliation participant is recorded in the registry as being responsible for the ICP; and (b) 1 or more certified metering installations are in place in accordance with this Part; and (c) <u>in the case of an ICP that has not previously been energised</u>, the owner of the network to which the point of connection is connected has given written approval. <p>(2) A reconciliation participant that meets the requirements of subclause (1)(a)—</p> <ul style="list-style-type: none"> (a) may authorise a metering equipment provider, with which it has an arrangement, to request the temporary energisation of a point of connection:

	<p>(b) may authorise energisation of an ICP if—</p> <ul style="list-style-type: none"> (i) a metering installation is in place at the ICP; and (ii) the metering installation is operational but not certified; and (iii) the reconciliation participant arranges for the certification of the metering installation to be completed within 5 business days of the energisation date: <p>(c) may energise an ICP if the point of connection is solely for unmetered load.</p> <p>(3) A reconciliation participant must not authorise the energisation of a point of connection in any of the following circumstances:</p> <ul style="list-style-type: none"> (a) a distributor has de-energised the point of connection for safety reasons, and has not subsequently approved the energisation: (b) the energisation of the point of connection would breach the Electricity (Safety) Regulations 2010. <p>(4) No participant may energise a point of connection, or authorise the energisation of a point of connection, other than a reconciliation participant as described in subclauses (1) to (3).</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. It would remove undue costs on parties in the case of re-energising connections, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>

Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	A quantitative cost benefit analysis has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to improve the efficient operation of the electricity industry by removing undue costs on parties re-energising connections.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants.</p> <p><u>Benefits</u></p> <p>The benefit from implementing the proposed amendment would be a reduction in potential compliance costs. If the Code were to be enforced as written, it would impose significant compliance costs on industry participants.</p> <p>In 2014, on average, retailers de-energised approximately 2,000 ICPs each month for non-payment of an electricity invoice.⁹ If the Authority were to enforce the Code as currently drafted, this would equate to a monthly cost of approximately \$16,500 for distributors to give written approval for these points of connection to be energised, using the following assumptions:</p> <ul style="list-style-type: none"> • five minutes of time required by each of the retailers requesting approval and the distributors granting written

⁹ Electricity Authority, 2015, Disconnections for non-payment January 2006 – December 2014, p. 7, available at http://www.emi.ea.govt.nz/Datasets/download?directory=%2FDatasets%2FRetail%2FDisconnections%2F20141231_disc%2Fconnections_for_non_payment.pdf.

	<p>approval</p> <ul style="list-style-type: none"> • an hourly labour rate of \$50 for the retailer and distributor personnel lodging and approving each request.¹⁰ <p>The Authority estimates there would be approximately the same number of disconnections for vacant premises, and therefore approximately the same monthly cost.</p> <p>Enforcing the current Code would also delay re-energisation of a consumer's premise. Re-energisation after either a debt was paid or a consumer moved into a de-energised premise, could be delayed by at least 1 business day.</p> <p><u>Net benefit</u></p> <p>On the basis of the above analysis the Authority considers the proposed amendment would have a positive net benefit.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>An alternative to the proposal is the status quo. This would impose undue costs.</p> <p>Another alternative would be to revoke clause 10.33(1)(c), so that the network owner's approval is never required. The risk with that alternative is that an energisation may occur when a network owner, had it been consulted, would have raised safety concerns and ultimately there could be unsafe energisations.</p> <p>Accordingly, the Authority is satisfied that the proposed amendment is the best alternative.</p>

¹⁰ i.e. an annual labour cost of \$100,000, and 250 working days in a calendar year.

Modification of metering installations: clause 10.34

Reference number(s)	078-007
Issue	<p>Clause 10.34 relates to the installation and modification of metering installations at points of connection that are not points of connection to the grid. Subclause (2) requires the metering equipment provider to consult with, and use its best endeavours to agree with, the distributor and trader for the relevant point of connection on specified matters before finalising the design of a metering installation.</p> <p>The intention was that the Code would also require the metering equipment provider to consult with the distributor and trader before modifying a metering installation. This is reflected in subclause (1), which states that the clause applies both when a metering installation is installed and when it is proposed to be modified. However, the requirement to consult when modifying a metering installation was not carried down to subclause (2). Accordingly, it is unclear whether the metering equipment provider must consult and agree when modifying a metering installation.</p> <p>In addition, subclause (1) contains a minor error in that it states that the clause applies “to each metering installation” proposed to be installed or modified. This should say that the clause applies to a metering equipment provider when the metering equipment provider proposes to install or modify the metering installation.</p>
Proposal	<p>The proposal is to amend clause 10.34(2) to clarify that the metering equipment provider must consult with the distributor and trader for the relevant point of connection on the specified matters before finalising the design of a metering installation, as well as before modifying a metering installation.</p> <p>It is also proposed that subclause (1) be amended to resolve the minor error referred to above, along with a number of minor changes to improve the readability of the clause.</p>
Proposed Code amendment	<p>10.34 Installation and modification of metering installations</p> <p>(1) This clause applies to <u>a metering equipment provider that proposes to install or modify a</u>each metering installation <u>at a point of connection other than a point of connection to the grid.</u>—</p> <p>(a) proposed to be installed at a point of connection other than a point of connection to the grid; or</p>

	<p>(b) at a point of connection other than a point of connection to the grid, which is proposed to be modified.</p> <p>(21A) A <u>The metering equipment provider</u> must, if this clause applies, consult with and use its best endeavours to agree with the distributor and the trader for the point of connection, before the design of the metering installation is finalised, on the matters specified in subclause (2), before—</p> <p>(a) <u>finalising the design of a metering installation for the point of connection; or</u></p> <p>(b) <u>modifying the design of a metering installation installed at the point of connection.</u></p> <p>(2) <u>The matters referred to in subclause (1A) are the metering installation's—</u></p> <p>(a) required functionality; and</p> <p>(b) terms of use; and</p> <p>(c) required interface format; and</p> <p>(d) integration of the ripple receiver and the meter; and</p> <p>(e) functionality for controllable load.</p> <p>(3) Each participant involved in the consultation referred to in subclause (2) must—</p> <p>(a) use its best endeavours to reach agreement; and</p> <p>(b) act reasonably and in good faith.</p> <p>(4) ...</p>
<p>Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act</p>	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Requiring a metering equipment provider to consult with the relevant distributor and trader before modifying a metering installation will ensure that metering installations are fit for purpose and that the correct pricing and tariff structures are used. Ultimately, the process will ensure that metering installations meet the requirements of all necessary participants before the metering equipment provider modifies them.</p> <p>For the same reason, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
<p>Assessment against Code amendment</p>	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>

principles	
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	A quantitative cost benefit analysis has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	<p>The objectives of the proposal are to:</p> <ul style="list-style-type: none"> contribute to the efficient operation of the electricity industry by ensuring that metering installations meet the requirements of all necessary participants (metering equipment provider, trader, and distributors) before the metering installations are installed or modified resolve minor drafting errors in clause 10.34.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority understands that the overwhelming majority of metering equipment providers, retailers and distributors already have arrangements in place for the metering equipment provider to consult with the relevant trader and distributor before modifying a metering installation. This is to avoid the cost associated with the metering equipment provider having to re-modify a metering installation because the original modification did not meet the requirements of the retailer or distributor.</p> <p>The Authority has therefore estimated the cost of implementing the proposal on the basis that approximately 10% of existing metering</p>

equipment providers, retailers and distributors *do not* have in place such arrangements.¹¹

The Authority estimates two days effort for each of the remaining eight organisations to develop processes that take into account the need for metering equipment providers to consult with the relevant trader and distributor before modifying a metering installation. The Authority considers this could be done using existing communication mechanisms.

The Authority also considers the processes implemented would be a one-off design issue. Designs are not changed often, meaning that any incremental ongoing operating cost for metering equipment providers, retailers and distributors would be negligible.

Assuming an annual labour cost of \$100,000 for each organisation's relevant staff members to establish the necessary process(es), the implementation cost of the proposal across all eight organisations would be approximately \$6,500.¹²

The Authority estimates these organisations would face approximately the same annual ongoing cost to administer the necessary process(es).

Benefits

Requiring a metering equipment provider to consult with the relevant distributor and trader before modifying a metering installation would ensure the metering installation met their requirements before it was modified.

If the metering equipment provider failed to do this (eg, the distributor wanted reactive or apparent power measured but the installation did not do this), the metering equipment provider would need to re-modify the metering installation. The Authority estimates this would cost approximately \$150 per installation. This cost includes:

- site visit
- reprogramming or possibly replacing components
- recertification of the metering installation
- updating metering records in the registry
- modifying the retailer's invoicing records.

¹¹ Meaning the Authority is assuming that approximately three retailers, two metering equipment providers and three distributors *do not* have in place such arrangements. By 'retailers' the Authority means 'retail brands'.

¹² Assuming 250 business days in a calendar year.

	<p><u><i>Net benefit</i></u></p> <p>Based on the above analysis, the proposed amendment would have a positive net benefit if it avoided at least 45-50 metering installations being re-modified per annum (assuming a relatively constant number of metering equipment providers, retailers and distributors over time). Based on its experience, the Authority considers that the number of metering installations requiring re-modification would be significantly more than this should the proposed amendment not proceed.</p> <p>Accordingly, the Authority is satisfied that the proposed amendment has a positive net benefit.</p>
<p>Evaluation of alternative means of achieving the objectives of the proposed amendment</p>	<p>The only alternative to the proposal would be the status quo. The risk associated with the status quo is that a metering equipment provider may not consult with the relevant trader and distributor before modifying a metering installation.</p> <p>If a metering installation does not meet the requirements of the relevant distributor and trader, the metering equipment provider may need to replace the metering installation at additional cost.</p> <p>Alternatively, the distributor and trader may have to use old pricing structures and tariffs, which would involve additional cost to allow for this in their processes.</p> <p>Accordingly, the Authority is satisfied that the proposed amendment is the best alternative.</p>

Measurement of reactive energy on category 2 metering installations: clause 10.37

Reference number(s)	079-008
Issue	<p>The Code currently requires category 2, half-hour metering installations that were certified after 29 August 2013 to measure and record both active and reactive energy.</p> <p>However, the Code should only require that such a metering installation is <u>capable</u> of measuring and recording reactive energy. Whether it is required to activate that capability and actually measure and record reactive energy depends on whether the distributor or trader has that particular need. Activating that capability is a significant cost to metering equipment providers.</p> <p>Under clause 10.34, a metering equipment provider consults with the distributor and the trader over the required functionality of new or modified metering installations. They may agree that the required functionality should include measuring and recording reactive energy or, if they cannot agree, the Authority can determine the matter.</p> <p>Accordingly, whether a particular category 2 metering installation is required to actually measure and record reactive energy can be determined under clause 10.34 and need not be a minimum requirement of all such meters under clause 10.37.</p>
Proposal	<p>The proposal is to amend the Code so that category 2, half-hour metering installations certified after 29 August 2013 are:</p> <ul style="list-style-type: none"> • required to be capable of measuring and recording reactive energy (new subclause (1A) in clause 10.37); but • not always required to measure and record reactive energy (new subclause (1B) in clause 10.37). Whether a particular category 2 metering installation is required to actually measure and record reactive energy will depend on any agreement reached, or determination made by the Authority, under clause 10.34. <p>The exception in subclause (2) of clause 10.37 will continue to apply. That is, category 2, half-hour metering installations certified after 29 August 2013 that are for a point of connection to the grid are required to measure and separately record both active and reactive energy.</p>
Proposed Code	10.37 Active and reactive measuring and recording requirements

<p>amendment</p>	<p>(1) A metering equipment provider must ensure that each half-hour metering installation which that is a category 23 metering installation, certified after 29 August 2013, measures and separately records, in accordance with this Part,—</p> <p>(a) if the measuring and recording requirement is for consumption only—</p> <p>(i) import active energy; and</p> <p>(ii) import reactive energy; and</p> <p>(iii) export reactive energy; or</p> <p>(b) if the measuring and recording requirement is for consumption and generation, or generation only—</p> <p>(i) import active energy; and</p> <p>(ii) export active energy; and</p> <p>(iii) import reactive energy; and</p> <p>(iv) export reactive energy.</p> <p><u>(1A) A metering equipment provider must ensure that each half-hour metering installation that is a category 2 metering installation, certified after 29 August 2013, is capable of measuring and recording—</u></p> <p><u>(a) import active energy; and</u></p> <p><u>(b) export active energy; and</u></p> <p><u>(c) import reactive energy; and</u></p> <p><u>(d) export reactive energy.</u></p> <p><u>(1B) A metering equipment provider must ensure that each half-hour metering installation that is a category 2 metering installation, certified after 29 August 2013, measures and separately records, in accordance with this Part,—</u></p> <p><u>(a) if the measuring and recording requirement is for consumption only, import active energy; or</u></p> <p><u>(b) if the measuring and recording requirement is for consumption and generation, or generation only—</u></p> <p><u>(i) import active energy; and</u></p> <p><u>(ii) export active energy.</u></p> <p>(2) Despite subclauses (1)(a) and (1B)—</p> <p>(a) each metering installation, for a point of connection to the grid, certified after 29 August 2013, must measure and separately record—</p> <p>(i) import active energy; and</p> <p>(ii) export active energy; and</p> <p>(iii) import reactive energy; and</p> <p>(iv) export reactive energy; and</p> <p>(b) the accuracy of each local service metering installation</p>
------------------	--

	for electricity used in and by a grid substation must be within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Ensuring that category 2, half-hour metering installations certified after 29 August 2013 are only required to measure and record reactive energy when the distributor or trader has that particular need will remove unnecessary compliance costs.</p> <p>In relation to section 32(1)(c) of the Act, the proposed amendment is desirable to promote the efficient operation of the electricity industry.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address an inefficiency created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this amendment. Accordingly, a qualitative analysis assessment has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objectives of the proposal are to reduce unnecessary compliance costs for metering equipment providers with regards to measuring and recording reactive energy in category 2, half-hour metering installations certified after 29 August 2013.
Evaluation of the costs and benefits of the proposed	The Authority considers the proposed amendment would have a positive net benefit.

<p>amendment</p>	<p><u><i>Costs</i></u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants.</p> <p><u><i>Benefits</i></u></p> <p>The benefit of implementing the proposed amendment would be the avoidance of unnecessary costs in relation to:</p> <ul style="list-style-type: none"> • modifying the set-up of category 2 metering installations • metering interrogation costs for reactive power consumption • retrieving reactive power consumption data from the metering installation • storage and management of reactive power consumption data. <p>Although the Authority is unable to quantify these costs, it estimates they could total many thousands of dollars per annum for all category 2 metering installations in New Zealand, with no corresponding benefit. Participants would pass these costs on to consumers in the form of increased meter lease or meter reading costs.</p> <p><u><i>Net benefit</i></u></p> <p>Based on the analysis above, the Authority considers the proposed amendment would have a positive net benefit.</p>
<p>Evaluation of alternative means of achieving the objectives of the proposed amendment</p>	<p>The only other option would be the status quo, which would be to leave the requirement in the Code. This would mean significant cost imposed on metering equipment providers to ensure that all category 2, half-hour metering installations certified after 29 August 2013 were measuring and recording reactive energy.</p> <p>Given that the objective of this proposal is to reduce unnecessary compliance costs, the proposed option is the most appropriate.</p>

Recertification requirements for installation of meters: clause 26 of Schedule 10.7

Reference number(s)	087-009
Issue	<p>Clause 26(2) of Schedule 10.7 provides that, if a meter has been moved to a new metering installation, an ATH cannot certify that metering installation unless the meter has been recalibrated.</p> <p>The Authority considers that this should not be required if:</p> <ul style="list-style-type: none"> the metering installation is a category 1 metering installation the meter was installed at the previous metering installation within the past 12 months the meter had not previously been moved from another metering installation without being recalibrated the ATH is satisfied that external factors have not affected the accuracy of the meter. <p>Requiring meters to be recalibrated in this situation imposes significant costs on metering equipment providers, with no benefit in terms of the meter's accuracy.</p> <p>A similar exception is already contained in clause 43(2) of Schedule 10.7. However, it is not clear that clause 43(2) overrides clause 26(2).</p>
Proposal	<p>The proposal is to:</p> <ul style="list-style-type: none"> make it clear in clause 26(2) that it is subject to the exception in clause 43(2) amend clause 43(2) to state more clearly the conditions that must be satisfied for the exception to apply. <p>Under the proposed new paragraph (c) of clause 43(2), if a meter had been installed in the previous metering installation without being recalibrated, then the exception would not apply and a calibration laboratory or ATH would need to recalibrate the meter. That would be the case even if the move from the earlier metering installation to the previous installation was within a 12 month period. This means that if a meter is repeatedly moved from one metering installation to another within 12 month periods, it would still have to be recalibrated in all but the first of those moves.</p>

<p>Proposed Code amendment</p>	<p>26 Requirements for metering installation incorporating meter</p> <p>(1) A metering equipment provider must ensure that each meter in a metering installation for which it is responsible is certified in accordance with this Part.</p> <p>(2) An ATH must, unless clause 43(2) applies, before it certifies a metering installation incorporating a meter, if the meter had previously been used in another metering installation, ensure that the meter has been recalibrated since it was removed from the previous metering installation, by—</p> <p>(a) an approved calibration laboratory; or</p> <p>(b) an ATH.</p> <p>(3) ...</p> <p>...</p> <p>43 Metering components must be certified</p> <p>(1) An ATH must, before it certifies a metering installation, ensure that each metering component that is required to be certified under this Part and which is in the metering installation—</p> <p>(a) is certified by an ATH in accordance with this Part; and</p> <p>(b) since certification, has been appropriately stored and not used.</p> <p>(2) Despite subclause (1) and clause 26(2), an ATH may certify a category 1 metering installation that contains a meter which has been certified and subsequently installed in, and removed from, another category 1 metering installation, in which case, the ATH must (the "previous metering installation") if the <u>ATH</u>—</p> <p>(a) be <u>is</u> satisfied that external factors have not affected the accuracy of the meter; and</p> <p>(b) check and confirm in the certification report for the metering installation that the date on which the meter was previously installed in the other metering installation is less than 12 months before the commissioning date of the metering installation that the ATH is certifying.</p> <p>(b) <u>has confirmed that the meter was installed in the previous metering installation for no more than 12 months; and</u></p> <p>(c) <u>has confirmed that the meter was calibrated or recalibrated before being installed in the previous metering installation and after being removed from any other metering installation in which the meter was previously installed.</u></p>
<p>Assessment of proposed Code amendment</p>	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry, by ensuring that unnecessary costs are not imposed on</p>

against the Authority's objective and section 32(1) of the Act	<p>metering equipment providers.</p> <p>In relation to section 32(1)(c) of the Act, the amendment is desirable to promote the efficient operation of the electricity industry.</p> <p>The proposed amendment would have no effect on competition or reliability of supply of electricity.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	A quantitative cost benefit analysis has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to contribute to the efficient operation of the electricity industry by clarifying the recertification requirements for re-installations of meters.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The proposed amendment is expected to place no additional costs on industry participants.</p> <p><u>Benefits</u></p> <p>The benefit from implementing the proposed amendment would be the avoidance of the cost of unnecessarily recalibrating a meter.</p> <p>The Authority estimates the cost of recalibrating a category 1 meter to be approximately \$50.</p>

	<p>The Authority estimates there may be approximately 500 ICPs created each month that result in the unnecessary recalibration of a category 1 meter. This estimate is based on data the Authority has showing the number of ICPs decommissioned and created each month.¹³</p> <p>The Authority therefore estimates that the electricity industry would incur approximately \$25,000 of unnecessary expenditure each month recalibrating category 1 meters, if the Code were to be enforced as currently drafted.</p> <p><u><i>Net benefit</i></u></p> <p>Based on the above analysis the Authority therefore believes the proposed amendment has a positive net benefit.</p>
<p>Evaluation of alternative means of achieving the objectives of the proposed amendment</p>	<p>The only alternative to the proposal is the status quo. The problem with the status quo is that it would impose costs on metering equipment providers who would need to recalibrate meters unnecessarily.</p> <p>Accordingly, the Authority is satisfied that the proposed amendment is the best alternative.</p>

¹³ Approximately 2,000 ICPs are created each month and approximately 1,000 ICPs are decommissioned each month.

Remedying an event of default: clauses 11.15C and 14.41 to 14.43

Reference number(s)	089-010
Issue	<p>The Authority can be notified of events of default in three different situations:</p> <ul style="list-style-type: none"> • under clause 14.41(h), when a distributor notifies the Authority of an event of default relating to the termination of a trader's use-of-system agreement • under clause 14.43(1), when a participant notifies the Authority of an event of default in relation to that participant • under clause 14.43(4), when the clearing manager notifies the Authority that an event of default has occurred. <p>Under clause 14.42, the clearing manager also notifies the Authority that it believes an event of default is likely to occur.</p> <p>In any of the three situations listed above, clause 11.15C provides that, if the Authority is satisfied that a trader has committed an event of default under clause 14.41(a), (b), (f), or (h), the Authority and the participant must follow the process for resolving the event of default in Schedule 11.5.</p> <p>However, once the process under Schedule 11.5 is under way, the Code does not require the participant that advised of the event of default to subsequently advise the Authority or the clearing manager if the event of default is remedied. This is inefficient because once an event of default is remedied there is no further need for the process under Schedule 11.5 to continue.</p>
Proposal	<p>Once the process under Schedule 11.5 is under way, it would be efficient to require the participant that advised of the event of default to subsequently advise the Authority and the clearing manager if the event of default is remedied. This would allow the process under Schedule 11.5 to end at the earliest possible instance.</p>
Proposed Code amendment	<p>11.15C Process for trader events of default</p> <p>(1) This clause applies if the Authority is satisfied that a trader has committed an event of default under paragraph (a) or (b) or (f) or (h) of clause 14.41.</p> <p>(2) The Authority and each participant must comply with Schedule 11.5.</p> <p>(3) <u>This clause ceases to apply, and the Authority and each</u></p>

	<p>participant must cease to comply with Schedule 11.5, if the Authority is advised under clause 14.41(2), 14.43(3B), or 14.43(4A) that the relevant participant considers that the event of default has been remedied.</p> <p>...</p> <p>14.41 Definition of an event of default</p> <p>(1) Each of the following events constitutes an event of default:</p> <p>...</p> <p>(h) termination of a trader's use-of-system agreement with a distributor because of a serious financial breach if—</p> <p>(i) the trader continues to have a customer or customers on the distributor's local network; and</p> <p>(ii) there are no unresolved disputes between the trader and the distributor in relation to the termination; and</p> <p>(iii) the distributor has not been able to remedy the situation in a reasonable time; and</p> <p>(iv) the distributor gives notice to the Authority that this <u>subclause</u> clause applies.</p> <p>(2) <u>If a distributor, having given notice under subclause (1)(h)(iv), considers that an event of default no longer exists, the distributor must advise the Authority that it considers that the event of default has been remedied.</u></p> <p style="text-align: center;"><i>Procedure for event of default</i></p> <p>14.42 Clearing manager to advise Authority of anticipated event of default</p> <p>(1) If the clearing manager believes that an event of default is likely to occur, the clearing manager must advise the Authority so that the Authority can consider an appropriate course of action.</p> <p>(2) <u>If the clearing manager, having advised the Authority under subclause (1), no longer believes that an event of default is likely to occur, the clearing manager must advise the Authority that it no longer believes that the event of default is likely to occur.</u></p>
--	---

14.43 Procedure upon event of default

- (1) If an **event of default** occurs in relation to a **participant**, the **participant** must immediately advise the **clearing manager** and the **Authority** of the **event of default**.
- (2) Despite subclause (1), a **participant** is not required to advise the **clearing manager** or the **Authority** if the **participant** would breach section 36 of the Corporations (Investigation and Management) Act 1989 by advising the **clearing manager** or the **Authority**.
- (3) If subclause (2) applies, the **participant** must seek the consent of the Registrar of Companies or the Financial Markets Authority (as applicable) to disclose the matter to the **clearing manager** and the **Authority**.
- (3A) If a **participant**, having advised of an **event of default** under subclause (1), considers that the **event of default** has been remedied, the **participant** must advise the **clearing manager** that it considers that the **event of default** has been remedied.
- (3B) If the **clearing manager** has been advised under subclause (3A) that the **participant** considers that an **event of default** has been remedied, the **clearing manager** must—
 - (a) decide whether it agrees that the **event of default** has been remedied; and
 - (b) if it agrees, advise the **Authority** that it considers that the **event of default** has been remedied.
- (4) If the **clearing manager** becomes aware that an **event of default** under paragraphs (a) to (g) of clause 14.41 has occurred and is continuing in relation to a **participant**, the **clearing manager** must—
 - (a) advise the **Authority** that the **event of default** has occurred; and
 - (b) if the **participant** has not advised the **clearing manager** of the **event of default**, advise the defaulting **participant** that the **event of default** has occurred.
- (4A) If the **clearing manager**, having advised of an **event of default** under subclause (4), considers that the **event of default** has been remedied, the **clearing manager** must advise the

	<p><u>Authority that it considers that the event of default has been remedied.</u></p> <p>(5) <i>[Revoked]</i></p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it promotes the efficient operation of the electricity industry for the long-term benefit of consumers.</p> <p>The proposed amendment would achieve this by, once the process under Schedule 11.5 is under way, requiring the participant that advised of the event of default to subsequently advise if the event of default has been remedied. This would allow the process under Schedule 11.5 to end at the earliest possible instance.</p> <p>Given that most events of default are remedied shortly after a participant advises of an event of default, this would reduce the likelihood of the Authority and the defaulting trader unnecessarily proceeding through the process under Schedule 11.5.</p> <p>Accordingly, the proposed amendment is desirable to promote the efficient operation of the electricity industry under section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	As discussed above, the proposed amendment is consistent with the Authority's objective under the Act and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 because it can be demonstrated that the proposed amendment would improve the efficiency of the electricity industry for the long-term benefit of consumers.
Principle 3: Quantitative Assessment	It is not practicable to quantify the costs and benefits of the proposed amendment. Accordingly, a qualitative assessment has been undertaken (see below).
Regulatory Statement	

Objectives of the proposed amendment	<p>As outlined above, the objectives of the proposed amendment are to promote the efficient operation of the electricity industry by requiring a participant that advises of an event of default to subsequently advise if the event of default has been remedied.</p> <p>Given that most events of default are remedied shortly after a participant advises of the event of default, this would reduce the likelihood of the Authority and the defaulting participant unnecessarily commencing the process under Schedule 11.5.</p> <p>This would allow the process under Schedule 11.5 to end at the earliest possible instance.</p>
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place negligible additional costs on industry participants because:</p> <ul style="list-style-type: none"> the obligation imposed has a negligible administrative cost associated with it (an e-mail advising the Authority that an event of default has been remedied would suffice) the obligation is very infrequent (since events of default are rare). <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment is that it would prevent an unnecessary cost on the Authority and other participants (eg, the registry and distributors) who are taking actions in accordance with Schedule 11.5 of the Code. These avoided costs could potentially be several thousand dollars; possibly many thousands of dollars.</p> <p><u>Net benefit</u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposed amendment is the status quo. The status quo does not require the participant that advised of the event of default to subsequently advise the Authority or the clearing manager if the event of default is remedied. This is inefficient because once an event of default has been remedied there is no further need for the process under Schedule 11.5 to continue.</p> <p>Accordingly, the Authority is satisfied that the proposed amendment</p>

	is the best alternative.
--	--------------------------

**Information a metering equipment provider must provide to registry:
Table 1 of Schedule 11.4**

Reference number(s)	046-011
Issue	<p>Rows 22 to 31 of Table 1 of Schedule 11.4 specifies the information that metering equipment providers (MEPs) are "Required" to provide about specific registry terms for different types of metering components, including meters, data storage devices and control devices.</p> <p>The issue is that the terms "meter", "data storage device", and "control device" are too broad. As a result, MEPs are required to provide more information than the Authority requires for the purposes of the Code.</p> <p>By way of background, the information specified in Table 1 of Schedule 11.4 is required because of the following clauses:</p> <ul style="list-style-type: none"> (a) clause 11.8A(1), which provides that an MEP must, for certain types of metering installation for which it is responsible, provide to the registry the registry metering records and update the registry metering records in accordance with Schedule 11.4 (b) clause 7(1) of Schedule 11.4, which provides that MEPs must, if required under Part 11, provide to the registry the information indicated in Table 1 as being "Required" for each metering installation for which it is responsible.
Proposal	<p>The proposal is to amend rows 22 to 30 of Table 1 of Schedule 11.4 to provide that MEPs are required to provide the information for a meter or data storage device only if the meter or data storage device returns active energy, reactive energy, apparent energy, or apparent power values as a result of an interrogation.</p> <p>It will be optional for MEPs to provide the information described in those rows for all other metering components (including load control devices).</p> <p>Note that there is a separate proposal to also amend the 'Description' column for item 30 in the Table.</p> <p>Row 31 is not amended but is provided below for reference.</p>
Proposed Code amendment	Table 1 of Schedule 11.4:

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
The following details for each metering component identified in rows 15 to 21 above				
22	metering component type	the metering component type identifier selected from the list of codes in the registry	Required for <u>meter or data storage device</u> that returns any 1 or more of the following values as a result of an <u>interrogation:</u> (a) <u>active energy:</u> (b) <u>reactive energy:</u> (c) <u>apparent energy:</u> (d) <u>apparent power.</u> <u>Optional for all other metering components.</u>	Required for <u>meter or data storage device</u> that returns any 1 or more of the following values as a result of an <u>interrogation:</u> (a) <u>active energy:</u> (b) <u>reactive energy:</u> (c) <u>apparent energy:</u> (d) <u>apparent power.</u> <u>Optional for all other metering components.</u>
23	register number	a sequential number that identifies each data channel that is present in the metering component	Required for meter or data storage device or control device that returns any 1 or more of the following values as a	Required for meter or data storage device or control device that returns any 1 or more of the following values as a

				<u>result of an interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering components.	<u>result of an interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering components.
	24	number of dials	the number of dials or digits that relate to the data channel	Required for meter or data storage device that returns any 1 or more of the following values as a result of an <u>interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering components.	Required for meter or data storage device that returns any 1 or more of the following values as a result of an <u>interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering components.
	25	register content code	an identifier for the contents of a channel or a data	Required for meter or data storage device that returns any 1	Required for meter or data storage device that returns any 1

			channel, selected from a list in the registry	or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power. Optional for all other metering components.	or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power. Optional for all other metering components.
	26	period of availability	an identifier for the period of availability for which a control device is configured, selected from a list in the registry	Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power. Optional for all other metering components.	Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation: (a) active energy: (b) reactive energy: (c) apparent energy: (d) apparent power. Optional for all other metering components.
	27	unit of measurement	an identifier for the units	Required for meter or data	Required for meter or data

			recorded in a data channel, selected from a list in the registry	storage device that <u>returns any 1 or more of the following values as a result of an interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering components.	storage device that <u>returns any 1 or more of the following values as a result of an interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering components.
	28	energy flow direction	an identifier for the import or export recording in the data channel, selected from a list in the registry	Required for meter or data storage device that <u>returns any 1 or more of the following values as a result of an interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering	Required for meter or data storage device that <u>returns any 1 or more of the following values as a result of an interrogation:</u> <u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u> Optional for all other metering

	29	accumulator type	an identifier for either absolute or cumulative recording in the data channel, selected from a list in the registry	components. Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) active energy: (b) reactive energy: (c) <u>apparent energy:</u> (d) <u>apparent power.</u> Optional for all other metering components.	components. Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) active energy: (b) reactive energy: (c) <u>apparent energy:</u> (d) <u>apparent power.</u> Optional for all other metering components.
	30	settlement indicator	an identifier ... ^[14]	Required for meter, or data storage device, or load control device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) active energy: (b) reactive energy: (c) <u>apparent</u>	Required for meter, or data storage device, or load control device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) active energy: (b) reactive energy: (c) <u>apparent</u>

¹⁴ Note that there is a separate proposal to also amend the 'Description' column for item 30.

				<u>energy:</u> <u>(d) apparent</u> <u>power.</u>	<u>energy:</u> <u>(d) apparent</u> <u>power.</u>
				<u>Optional for</u> <u>all other</u> <u>metering</u> <u>components.</u>	<u>Optional for</u> <u>all other</u> <u>metering</u> <u>components.</u>
	31	event reading	The event meter read of a meter or data storage device	Optional	Optional
	...				
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Removing the unnecessary obligations on MEPs will lead to improved operational efficiency.</p> <p>Accordingly, the amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>				
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.				
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.				
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.				
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a qualitative analysis has been undertaken (see below).				

Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to contribute to the efficient operation of the electricity industry by removing unnecessary obligations on MEPs.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants.</p> <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment is that it would remove an unnecessary cost on MEPs if the Authority were to enforce the Code requirement.</p> <p>Currently the Code requires MEPs to provide more information to the registry than the Authority requires for the purposes of the Code. The unnecessary costs faced by MEPs would include the collection, maintenance, and provision of data.</p> <p><u>Net benefit</u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	The only alternative to the proposal is the status quo. If the Authority pursued this option, MEPs would face significant costs in complying with the requirements. The costs would result in no benefit as the additional information is not required. Accordingly, the Authority is satisfied that the proposal is the best alternative.

Publication of transmission agreements: clause 12.15

Reference number(s)	047-012
Issue	<p>All parties that are physically connected to the transmission grid must have a transmission agreement with Transpower. These parties are known as designated transmission customers, and include distribution companies, major users that are directly connected to the grid, and generators that are directly connected to the grid.</p> <p>Clause 12.15(1) of the Code requires Transpower to provide certified copies of transmission agreements to the Authority. Clause 12.15(3) then requires the Authority to publish the agreements.</p> <p>The purpose of Transpower providing transmission agreements to the Authority, and the Authority then publishing them, is to ensure they are consistent in all material respects with the benchmark agreement and the grid reliability standards that are given effect under Part 12 of the Code.</p> <p>Transpower currently publishes the agreements on its own website and has an exemption (No.194) from clause 12.15(1). The exemption expires on 31 December 2015.</p> <p>The purpose of clause 12.15 of the Code can be achieved more efficiently than under the current drafting, without removing the ability of persons to obtain a copy of a transmission agreement.</p>
Proposal	<p>The proposal is to change how information about transmission agreements is published, by requiring Transpower:</p> <ul style="list-style-type: none"> to publish information about each transmission agreement (rather than requiring Transpower to provide a certified copy of each agreement to the Authority for publication on the Authority's website); and to provide a copy of a transmission agreement to any person on request.
Proposed Code amendment	<p><u>12.15 Transpower to publish information about transmission agreements and provide them on request</u> Transmission agreements to be provided to the Authority and published <u>(1) Transpower must publish and update annually a list of all transmission agreements it has with designated transmission</u></p>

	<p><u>customers that includes, in respect of each transmission agreement contained in the list, the following information:</u></p> <p>(a) <u>the full name of the designated transmission customer that is a party to the transmission agreement; and</u></p> <p>(b) <u>the date on which the transmission agreement was executed; and</u></p> <p>(c) <u>whether the transmission agreement includes any variations from the benchmark agreement; and</u></p> <p>(d) <u>if the transmission agreement includes any variations from the benchmark agreement, a description of the variations; and</u></p> <p>(e) <u>if any schedule to the transmission agreement has been revised in accordance with clause 12.12, the date from which the revised schedule began to apply.</u></p> <p>(1) Transpower must provide the Authority with a copy of each transmission agreement executed by Transpower as soon as reasonably practicable.</p> <p>(1A) A person may request from Transpower a copy of a transmission agreement that Transpower has with a designated transmission customer and Transpower must provide a copy to the person as soon as practicable after receiving the request.</p> <p>(2) The copy that is provided must be—</p> <p>(a) a copy of the complete transmission agreement; and</p> <p>(b) certified by a director or the chief executive of Transpower or the designated transmission customer, to the best of the director's or chief executive's knowledge and belief, to be a true and complete copy of the agreement.</p> <p>(3) The Authority must publish all transmission agreements between Transpower and designated transmission customers within a reasonable time of their receipt.</p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Amending Transpower's obligations in the manner proposed would lead to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment	The Authority is satisfied that the proposed amendment is consistent

against Code amendment principles	with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would make transmission agreement information available in a more accessible way, with lower search and transaction costs for interested parties, and at lower cost to Transpower and the Authority than the current requirements of clause 12.15.
Principle 3: Quantitative Assessment	A quantitative assessment of the proposal's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to improve the efficiency with which information about transmission agreements is made publicly available.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>If the proposal is compared to the counterfactual of Transpower complying with the Code as currently drafted, then the Authority expects that Transpower would incur the following costs:</p> <ul style="list-style-type: none"> • The cost of setting up and publishing information about transmission agreements on its website. Transpower has advised that currently it costs approximately \$2,000 each year to do this second activity under exemption no. 194. This equates to a present value of approximately \$17,000, assuming a 15 year discount period and a real discount rate of 8%. • The cost of providing an uncertified copy of a transmission agreement to a person who has requested it. The Authority believes this cost should be negligible if Transpower makes publicly available the information about transmission

	<p>agreements that people want.</p> <p><u><i>Benefits</i></u></p> <p>Compared to the counterfactual of Transpower complying with the Code as currently drafted, the key benefits of implementing the proposed amendment would be:</p> <ul style="list-style-type: none"> • Reduced transaction costs for parties seeking to understand the scope of, and changes to, transmission agreement information, including variations from the benchmark agreement (these parties would not need to review an agreement that is typically approximately 150 pages long). • Reduced compliance costs for Transpower (Transpower estimates a one-off saving of \$20,000 and ongoing savings of approximately \$5,500 per year from not having to collate and deliver large quantities of information about transmission agreements – these cost savings include avoiding the need to obtain Chief Executive or Director certification). • Reduced administrative costs for the Authority as a result of not receiving certified copies of transmission agreements from Transpower and publishing them on the Authority's website (the Authority estimates an annual saving of approximately \$1,000). <p>These last two benefits have a present value of approximately \$56,000 if we use a 15 year discount period, with a real discount rate of 8%.</p> <p>The Authority notes that these benefits are currently being realised under exemption no. 194, but does not consider it is appropriate to continue the current exemption indefinitely. It is not good regulatory practice to impose an obligation on a party, only to then exempt the party from the obligation.</p> <p><u><i>Net benefit</i></u></p> <p>Based on the analysis above, the Authority considers the proposed amendment would have a positive net benefit when compared with the current requirement under clause 12.15.</p>
<p>Evaluation of alternative means of achieving the objectives of the proposed amendment</p>	<p>The Authority has identified two alternative means of achieving the objective of the proposal amendment:</p> <ul style="list-style-type: none"> • continue granting exemptions to Transpower • require Transpower to publish on its website copies of transmission agreements (either certified or uncertified) that Transpower has entered into.

	<p>The first alternative is not preferred because, as noted above, the Authority does not consider it good regulatory practice to continue granting exemptions to Transpower.</p> <p>On balance, the Authority believes the proposal would have a higher net benefit than the second alternative primarily because the proposal would better facilitate reduced transaction costs for parties seeking to understand the scope of, and changes to, transmission agreement information, including variations from the benchmark agreement.</p>
--	--

Requirement to publish a centralised data set: clauses 12.72 to 12.75

Reference number(s)	049-013
Issue	<p>Clauses 12.72 to 12.75 require the Authority to establish, maintain and publish a centralised data set. The centralised data set was also required under the previous Electricity Governance Rules 2003 (Rules).</p> <p>The information that was published in a centralised data set is now published on the Authority's Electricity Market Information (EMI) website. Making the information available on this website is a better system for both the Authority and industry participants.</p> <p>The Authority considers that it is no longer necessary to separately publish a centralised data set.</p>
Proposal	<p>Revoke the definition of centralised data set from Part 1, and revoke clause 12.52(c) and clauses 12.72 to 12.75.</p> <p>Make consequential amendments to clause 12.116(2)(c) to remove a reference to the centralised data set.</p>
Proposed Code amendment	<p>centralised data set means information kept by the Authority relating to transmission and transmission alternatives under clauses 12.72 to 12.75</p> <p>...</p> <p>12.52 Contents of this subpart</p> <p>This subpart relates to—</p> <ul style="list-style-type: none"> (a) grid reliability standards; and (b) investment contracts; and (c) centralised data set; and (d) grid reliability reporting. <p>...</p> <p style="text-align: center;"><i>Centralised data set</i></p> <p>12.72 Authority to establish and maintain centralised data set</p> <p>(1) The Authority must establish and maintain a centralised data set.</p> <p>(2) The centralised data set at the commencement of this Code is the centralised data set published by the Electricity Commission under rule 11 of section II of part F of the rules immediately before this Code came into force.</p>

	<p>12.73 Purpose of centralised data set</p> <p>The purpose of the centralised data set is to support efficient planning processes by ensuring collection and ongoing maintenance by the Authority of the factual and historical information required to make efficient and effective decisions on transmission and transmission alternatives.</p> <p>12.74 Contents of centralised data set</p> <p>A centralised data set should include—</p> <ul style="list-style-type: none"> (a) provisions for updating and maintenance of data; and (b) information on network capabilities, performance and constraints. <p>12.75 Public access to centralised data set</p> <p>Subject to clause 12.54(4), the Authority must publish the centralised data set.</p> <p>...</p> <p>12.116 Information on capacities of individual interconnection assets</p> <p>...</p> <ul style="list-style-type: none"> (2) The information required under subclause (1)— <ul style="list-style-type: none"> (a) must be consistent with the manufacturer's specification for the asset or with the most recent asset capability statement provided by Transpower under clause 2(5) of Technical Code A of Schedule 8.3, if this differs from the manufacturer's specification; and (b) must be provided in a form that allows the branch to which each asset belongs to be easily identified; and (c) must be published either in the centralised data set maintained under clause 12.72 or some other form, if the Authority so determines must be published. If the Authority determines that the information must be published in different form, Transpower must publish the information in that in the form determined by the Authority as soon as reasonably possible practicable after the Authority has determined the different form.
<p>Assessment of proposed Code amendment against the Authority's</p>	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Publishing a centralised data set should no longer be required now that the Authority can publish the information on its Electricity Market Information (EMI) website. The Code</p>

objective and section 32(1) of the Act	<p>requirements for the Authority to establish, maintain, and publish a centralised data set are an unnecessary administrative cost on the Authority and are therefore an unnecessary cost to the electricity industry.</p> <p>Accordingly, the proposed amendment promotes the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	A quantitative cost benefit analysis has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to contribute to the efficient operation of the electricity industry by removing unnecessary obligations on the Authority to publish and maintain a centralised data set.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed Code amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants. However, if it did, they would be negligible. This is because the proposed amendment</p>

	<p>reflects current industry practice.</p> <p><u><i>Benefits</i></u></p> <p>The primary benefit of the proposed amendment is that it would remove what is now an unnecessary cost on the Authority, and therefore consumers.</p> <p>The EMI website makes available in a more timely and user-friendly manner all of the data contained in a central data set. It is significantly cheaper for the Authority to maintain the data via the EMI website than via a central data set. The Authority estimates its annual savings would be at least \$50,000, which equates to a present value of approximately \$430,000 (assuming a 15 year discount period and a real discount rate of 8%).</p> <p><u><i>Net benefit</i></u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment would outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposal is the status quo. If this option were pursued, the Authority would be faced with significant costs to comply with the requirement to publish and maintain a centralised data set. The cost would result in no benefit as the information available through such a centralised data set (along with other information) is already available through the EMI website. Accordingly, the Authority is satisfied that the proposal is the best alternative.</p>

Revocation of distributor indemnity from the Code: clause 12A.6 and Schedule 12A.1

Reference number(s)	093-014
Issue	<p>Clause 12A.6(1) requires every use-of-system agreement to include the distributor indemnity specified in Schedule 12A.1. The Code also provides that a distributor and a trader may agree to an indemnity that is more favourable to the trader (clause 12A.6(3)), and provides that a distributor and trader may agree to contract out of the requirement to include the indemnity in their use-of-system agreement (clause 12A.6(4)).</p> <p>The Authority included clause 12A.6 in the Code because section 42(2)(f) of the Electricity Industry Act 2010 required the Authority either to amend the Code to include "requirements for all distributors to use more standardised use-of-system agreements, and for those use-of-system agreements to include provisions indemnifying retailers in respect of liability under the Consumer Guarantees Act 1993 (CGA) for breaches of acceptable quality of supply, where those breaches were caused by faults on a distributor's network", or report to the Minister on why such requirements were not included in the Code.</p> <p>Following consultation, the Authority decided to amend the Code to include the distributor indemnity in clause 12A.6 and Schedule 12A.1. Clause 12A.6 came into force on 1 December 2011 (as part of the Electricity Industry Participation Code (Distributor Use-of-System Agreements and Distributor Tariffs) Code Amendment 2011). However, clause 12A.6(5) provides that the requirement to include an indemnity did not apply, until 1 May 2012, to a use-of-system agreement that was in force before 1 December 2011.</p> <p>Subsequent to the requirement for an indemnity in clause 12A.6 coming into force, the CGA was amended to include a distributor indemnity. That amendment came into effect on 17 June 2014. The indemnity is very similar to the indemnity in Schedule 12A.1. Key differences between the indemnities include:</p> <ul style="list-style-type: none"> • section 46A of the CGA refers to persons responsible for providing line function services, whereas Schedule 12A.1 refers specifically to distributors • the indemnity in section 46A is arguably wider than the indemnity in Schedule 12A.1, in that section 46A(1)(b) refers to the failure

	<p>being the result of an "event, circumstance, or condition" associated with the responsible party's electricity lines or other equipment, whereas Schedule 12A.1 refers only to an "event or condition"</p> <ul style="list-style-type: none"> the indemnity in Schedule 12A.1 provides that if a consumer makes a claim against the retailer and the retailer wishes to be indemnified, the retailer must as soon as reasonably practicable give written notice of the claim to the distributor specifying the nature of the claim in reasonable detail, and consult with and keep the distributor informed in relation to the claim. The indemnity in section 46A contains no equivalent provisions section 46A specifically provides that a failure of the acceptable quality guarantee is determined by either the retailer, through the dispute resolution scheme following a complaint made under section 95 of the Electricity Industry Act 2010, or by a Court or a Disputes Tribunal. In contrast, Schedule 12A.1 assumes that a failure has been determined section 46A provides that disputes between retailers and responsible parties relating to the existence or allocation of liability under the indemnity may be dealt with by the dispute resolution scheme in section 95 of the Electricity Industry Act. Schedule 12A.1 does not provide for dispute resolution. <p>Because distributor indemnities are now regulated under the CGA, the Authority considers that it is no longer necessary or appropriate to regulate distributor indemnities under the Code.</p> <p>The Authority notes that the removal of the indemnity requirement in the Code would not mean that participants would also have to amend their use-of-system agreements. If a use-of-system agreement contained a distributor indemnity, it is likely to be the case that the provisions relating to that indemnity would simply be unnecessary.</p>
Proposal	<p>The Authority proposes revoking clause 12A.6 and Schedule 12A.1 in their entirety, and making consequential amendments to clause 12A.1.</p>
Proposed Code amendment	<p>12A.1 Contents of this Part</p> <p>This Part—</p> <ul style="list-style-type: none"> (a) specifies requirements that must be complied with in negotiating use-of-system agreements; and (b) specifies requirements that must be complied with if prudential requirements are included in use-of-system agreements; and

	<p>(c) requires that an indemnity be included in every use-of-system agreement unless agreed otherwise; and</p> <p style="text-align: center;">...</p> <p>12A.6 Distributor indemnity</p> <p>(1) Every use-of-system agreement must include the clause specified in Schedule 12A.1.</p> <p>(2) Every use-of-system agreement that does not include the clause specified in Schedule 12A.1 is deemed to include that clause.</p> <p>(3) A distributor may include in a use-of-system agreement an indemnity that is more favourable to the trader than the indemnity specified in Schedule 12A.1, and, in that case, subclauses (1) and (2) do not apply to the use-of-system agreement.</p> <p>(4) This clause does not apply to a use-of-system agreement if the distributor and the trader who are parties to the use-of-system agreement agree to omit the clause specified in Schedule 12A.1 from the use-of-system agreement.</p> <p>(5) Subclause (1) does not apply, until 1 May 2012, to a use-of-system agreement that was in force before 1 December 2011.</p> <p>Schedule 12A.1 Distributor indemnity in use-of-system agreements</p> <p>Every use-of-system agreement is deemed to include the following clause:</p> <p>Distributor indemnity</p> <p>(1) If</p> <p style="padding-left: 40px;">(a) there has been a failure of the acceptable quality guarantee in section 6 of the Consumer Guarantees Act 1993 in the supply of electricity to a Consumer by the Retailer (a "failure"); and</p> <p style="padding-left: 40px;">(b) the failure was wholly or partially the result of an event or condition associated with the Distributor's Network; and</p> <p style="padding-left: 40px;">(c) the failure was not a result of the Distributor complying with a rule or order with which it was legally obliged to comply; and</p> <p style="padding-left: 40px;">(d) the Consumer obtains a remedy under Part 2 of the Consumer Guarantees Act 1993 in relation to the failure against the Retailer; and</p> <p style="padding-left: 40px;">(e) that remedy is a cost to the Retailer (a "remedy cost"), the Distributor indemnifies the Retailer for the remedy cost.</p>
--	--

	<p>(2) The amount of the Distributor's liability under this indemnity is limited to the proportion of the remedy cost that is attributable to the event or condition associated with the Distributor's Network.</p> <p>(3) However,</p> <p>(a) if the Distributor pays compensation to a Consumer ("payment A") in respect of a service provided directly by the Distributor to the Consumer; and</p> <p>(b) the Retailer incurs remedy costs in relation to the Consumer for a failure of acceptable quality that arose from the same event or circumstance that led to the payment of payment A; then</p> <p>(c) the amount that the Retailer would otherwise recover from the Distributor in respect of that Consumer must be reduced by the amount of payment A.</p> <p>(4) If a Consumer makes a claim against the Retailer that the Retailer wishes to be indemnified for under this indemnity (a "claim"), the Retailer will:</p> <p>(a) as soon as reasonably practicable, give written notice of the claim to the Distributor specifying the nature of the claim in reasonable detail; and</p> <p>(b) consult with and keep the Distributor informed in relation to the claim.</p>
<p>Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act</p>	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Given that the CGA specifically provides for a distributor indemnity, the Authority does not consider that it is necessary, or efficient, to maintain a duplicate provision in the Code. Removing a duplicate provision in the Code is likely to improve efficiency, as distributors and traders will be clear that the requirement that each distributor indemnify traders on its network derives from the CGA.</p> <p>Accordingly, the amendment is desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
<p>Assessment against Code amendment principles</p>	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>

Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the costs and benefits of this amendment. Accordingly, a qualitative assessment has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to contribute to the efficient operation of the electricity industry by removing an unnecessary duplicate provision in the Code. As noted above, this would also improve efficiency by making it clearer to distributors and traders that the requirement relating to the distributor indemnity derives from the CGA.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority does not expect the proposed amendment to place additional costs on industry participants.</p> <p><u>Benefits</u></p> <p>The primary benefit from implementing the proposed amendment would be a reduction in distributors' compliance costs.</p> <p>It is not good regulatory practice to have substantively the same obligation imposed under two different legislative instruments. This can cause confusion as to the respective obligations.</p> <p>The minor differences between the two obligations mean that distributors currently face compliance costs ensuring they do not breach the Code, which are additional to the costs they face in complying with the CGA. However, there is little or no benefit to consumers from the incremental cost of complying with the Code because the indemnity obligation in the Code is very similar to the obligation in the CGA.</p>

	<p>Having very similar indemnity obligations under the Code and the CGA also means that compliance enforcement costs are higher than necessary, because there is duplication of effort under the two compliance enforcement regimes.</p> <p>Although the Authority is unable to quantify the incremental compliance costs distributors face complying with both the Code and the CGA instead of complying only with the CGA, it expects they may have a net present value in the thousands of dollars. This is because of the number of distributors in New Zealand (29) that need to comply with the indemnity obligations in both the Code and the CGA. As noted above, these incremental costs provide little or no benefit to consumers.</p> <p><u><i>Net benefit</i></u></p> <p>Based on the analysis above, the Authority considers the proposed amendment would have a positive net benefit.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposal is the status quo. If this option were pursued, the benefits outlined above would not eventuate. Accordingly, the Authority is satisfied that the proposal is the best alternative.</p>

Amendment to prudential security provisions: clauses 12A.4 and 12A.5

Reference number(s)	050-015
Issue	<p>Clauses 12A.4 and 12A.5 of the Code relate to prudential security requirements between traders and distributors. An issue has arisen about when a distributor may require a trader to provide prudential security.</p> <p>Clause 12A.4(1)(c) allows a distributor to require that a use-of-system agreement between it and a trader require the trader to comply with prudential requirements. However, clause 12A.4(3) provides that, if a use-of-system agreement includes such a provision, the trader must elect which type of prudential security to provide before the commencement of the use-of-system agreement.</p> <p>The Code does not expressly allow distributors to require traders to provide prudential security part way through the term of a use-of-system agreement. However, it is open to a distributor and a trader to agree to a use-of-system agreement that provides that the distributor can require the trader to provide prudential security during the term of the agreement (rather than at the commencement of the agreement). That is because clause 12A.4(7) provides that a distributor and a trader may agree prudential requirements that are less onerous on the trader than the requirements set out in clause 12A.4. It is clearly less onerous on a trader if its use-of-system agreement provides that the distributor may require prudential security to be provided during the term of the agreement, rather than requiring the trader to provide prudential security from the commencement of the agreement. The Authority has published a model use-of-system agreement (interposed), which reflects that a distributor and retailer (which is the term used in the model agreement, rather than trader) could agree that the retailer will comply with prudential requirements if required to do so by notice from the distributor (see clause 12.1 of the model agreement).</p> <p>The Authority considers that it should amend the relevant Code provisions to more clearly set out the flexibility for distributors to require prudential security at any time during the term of a use-of-system agreement.</p>
Proposal	<p>The proposal is to:</p> <p>(a) amend the two prudential security clauses (12A.4 and 12A.5)</p>

	<p>by splitting them into four clauses (12A.4 to 12A.5A) to improve the readability of the clauses, including by making clause 12A.4(7), which states that the parties to a use-of-system agreement may agree to less onerous terms, a new standalone clause 12A.5A</p> <p>(b) amend clause 12A.4(1)(c) to state that proposed new clauses 12A.4A to 12A.5A apply in relation to a use-of-system agreement if the distributor requires the trader to comply with prudential requirements, or to comply with prudential requirements if required to do so by the distributor (which could be at any time during the term of the agreement)</p> <p>(c) amend clause 12A.4A(3) for clarity</p> <p>(d) revoke clause 12A.4(8), which specifies that clauses 12A.4 and 12A.5 do not apply to use-of-system agreements in force before 1 December 2011 until 1 May 2012. That subclause is a transitional provision that is now spent</p> <p>(e) make other consequential amendments to clauses 12A.4 and 12A.5.</p>
<p>Proposed Code amendment</p>	<p>12A.4 Prudential requirements</p> <p>(1) This clause and e <u>Clauses 12A.4A to 12A.5A apply in relation to a use-of-system agreement if—</u></p> <p>(a) the distributor party to the use-of-system agreement has 1 or more consumers connected to its network to whom the distributor does not send accounts for line function services directly; and</p> <p>(b) the distributor's charges for line function services are collected from consumers or paid by the trader party to the use-of-system agreement in accordance with the use-of-system agreement; and</p> <p>(c) the distributor requires that the use-of-system agreement provides that the trader—</p> <p><u>(i) must comply with prudential requirements; or</u></p> <p><u>(ii) must comply with prudential requirements if required to do so by the distributor.</u></p> <p><u>12A.4A Election of prudential requirements</u></p> <p>(1)2) <u>Subject to subclause 12A.5A(7), if a use-of-system agreement provides that the trader party to the use-of-system agreement must comply with prudential requirements, including if required to do so by the distributor, the use-of-system agreement must provide the use-of-system agreement must provide that the trader may elect to comply with the</u></p>

	<p>prudential requirements under the use-of-system agreement in either of the following ways:</p> <ul style="list-style-type: none"> (a) the trader must maintain an acceptable credit rating in accordance with subclause (3)4); or (b) the trader must provide and maintain acceptable security by, at the trader's election,— <ul style="list-style-type: none"> (i) providing the distributor with a cash deposit; or (ii) arranging for a third party with an acceptable credit rating to provide that security in a form acceptable to the distributor; or (iii) providing a combination of the securities described in subparagraphs (i) and (ii). <p>(2)3) The use-of-system agreement must provide that the trader—</p> <ul style="list-style-type: none"> (a)—must make the elections referred to in subclause (2) before the commencement of the use-of-system agreement; and (b)—may change an its election at any time. <p>(3)4) For the purposes of this clause, an acceptable credit rating means that the trader or the third party has an acceptable credit rating if it (as the case may be) —</p> <ul style="list-style-type: none"> (a) carries a long term credit rating of at least— <ul style="list-style-type: none"> (i) BBB- (Standard & Poors Rating Group); or (ii) a rating that is equivalent to the rating specified in subparagraph (i) from a rating agency that is an approved rating agency for the purposes of Part 5D of the Reserve Bank of New Zealand Act 1989; and (b) if the trader or the third party (as the case may be) carries a credit rating at the minimum level required by paragraph (a), is not subject to negative credit watch or any similar arrangement by the agency that gave it the credit rating. <p>(4)5) Subject to clause 12A.5, the value of the acceptable security described in subclause (2)1(b) must be the distributor's reasonable estimate of the line function services charges that the trader will be required to pay to the distributor in respect of any period of not more than 2 weeks.</p> <p>(5)6) A use-of-system agreement must specify that, if the trader elects to provide acceptable security as described in subclause (2)1(b), the distributor must—</p> <ul style="list-style-type: none"> (a) hold any security provided by the trader trader in the form of a cash deposit in a trust account in the name of the trader trader at an interest rate that is the best on-call rate reasonably available at the time the trader provides
--	---

	<p>the cash deposit; and</p> <p>(b) pay interest earned in respect of the cash deposit to the trader trader on a quarterly basis, net of account fees and any amounts that are required to be withheld by law.</p> <p>(7) Despite subclauses (2) to (6), a distributor and a trader may agree prudential requirements that are less onerous on the trader than the requirements described in subclauses (2) to (6).</p> <p>(8) This clause and clause 12A.5 do not apply, until 1 May 2012, to a use-of-system agreement that was in force before 1 December 2011.</p> <p>12A.5 Requirements if distributors require additional security</p> <p>(1) A distributor may require that its use-of-system agreement provides 1 or both of the following:</p> <p>(a) that if the trader elects to provide acceptable security as specified in clause 12A.4A(2)(1)(b), the trader must provide acceptable security that is additional to the amount provided for in clause 12A.4A(4)5):</p> <p>(b) that the distributor may, during the term of the use-of-system agreement, require the trader trader to provide such additional security.</p> <p>(2) If a use-of-system agreement has a provision provided for in subclause (1), the distributor must ensure that the total value of additional security specified in the use-of-system agreement must be such that the total value of all security required to be provided by the trader must not be more than the distributor's reasonable estimate of the line function services charges that the trader will be required to pay to the distributor in respect of any 2 month period.</p> <p>(3) If a use-of-system agreement has a provision provided for in subclause (1), the distributor must ensure that the use-of-system agreement provides the following:</p> <p>(a) if any additional security provided by the trader is in the form of a cash deposit, the distributor must pay a charge to the trader for each day that the distributor holds the additional security at a per annum rate equal to the sum of the bank bill yield rate for that day plus 15% on the amount of additional security held on that day:</p> <p>(b) if any additional security provided by the trader is in the form of security from a third party, the distributor must pay a charge to the trader for each day that the distributor holds the additional security at a per annum rate of 3% on the amount of additional security held on</p>
--	---

	<p>that day:</p> <p>(c) any money required to be paid by the distributor to the trader in accordance with <u>as specified in</u> paragraph (a) or paragraph (b) must be paid by the distributor to the trader on a quarterly basis.</p> <p>(4) For the purposes of this clause, the bank bill yield rate is—</p> <p>(a) the daily bank bill yield rate (rounded upwards to 2 decimal places) published on the wholesale interest rates page of the website of the Reserve Bank of New Zealand (or its successor or equivalent page) on that day as being the daily bank bill yield for bank bills having a tenor of 90 days; or</p> <p>(b) for any day for which such a rate is not available, the bank bill yield rate is deemed to be the bank bill yield rate determined in accordance with paragraph (a) on the last day that such a rate was available.</p> <p><u>12A.5A Agreement to less onerous terms</u></p> <p><u>Despite clause 12A.4A, a distributor and a trader may agree prudential requirements that are less onerous on the trader than the requirements described in clause 12A.4 to 12A.5.</u></p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the promotion of competition in the electricity industry. This is because a distributor could dispense with the requirement for prudential security from the commencement of the use-of-system agreement, which would lower traders' costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote competition in the electricity industry in accordance with section 32(1)(a) of the Act, and the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly	<p>The proposed amendment is consistent with principle 2 in that it</p>

Identified Efficiency Gain or Market or Regulatory Failure	would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the costs and benefits of this proposed amendment. Accordingly, a qualitative assessment has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	<p>The objectives of the proposal are to:</p> <ul style="list-style-type: none"> (a) contribute to the efficient operation of the electricity industry by more clearly setting out the options for distributors in relation to prudential security requirements in the Code (b) contribute to the promotion of competition in the electricity industry by giving distributors the flexibility to dispense with the requirement for prudential security from the commencement of the use-of-system agreement.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants. This is because the proposal does not place any new mandatory obligations on distributors and traders. It is at the discretion of a distributor whether it agrees to the trader providing prudential security during the term of a use-of-system agreement, rather than from the commencement of the agreement.</p> <p><u>Benefits</u></p> <p>The key benefit of the proposed amendment is that it would facilitate a reduction in the cost that traders/retailers face to serve consumers. As noted earlier, it is clearly less onerous on a trader if a use-of-system agreement states that prudential security may be required during the term of the agreement rather than at the outset. This lower cost-to-serve increases the attractiveness of competing for customers on the distributor's network.</p> <p><u>Net benefit</u></p> <p>The Authority considers that the net benefit of the proposed</p>

	amendment is positive.
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposal is the status quo. If that option were pursued, distributors would still be able to require traders to provide prudential security part way through the term of a use-of-system agreement, because clause 12A.4(7) provides that a distributor and a trader may agree prudential requirements that are less onerous on the trader than the requirements set out clause 12A.4.</p> <p>However, the lack of clarity about this issue would remain, meaning that the benefits outlined above would not eventuate. Accordingly, the Authority is satisfied that the proposal is the best alternative.</p>

Amendment to provisions relating to EIEPs: clause 12A.14

Reference number(s)	051-016
Issue	<p>Clause 12A.14(1) provides that if the Authority has published an electricity information exchange protocol (EIEP) (other than a voluntary EIEP), a distributor and a trader must comply with the EIEP when exchanging information to which the EIEP relates.</p> <p>Clause 12A.14(2) provides that the requirement to comply with an EIEP does not apply if the distributor and trader agree to exchange the information in any other way, and that agreement is recorded in their use-of-system agreement. Clause 12A.14(2) essentially allows the parties to a use-of-system agreement to contract out of the obligation to comply with an EIEP.</p> <p>It was intended that the parties to a use-of-system agreement should be able to contract out of the obligation to comply with an EIEP only after the EIEP is publicised. In other words, each time the Authority publicises an EIEP (other than an amendment to an existing publicised EIEP), a distributor and trader party to a use-of-system agreement must take positive action to opt-out of complying with the EIEP (and record that in their use-of-system agreement).</p> <p>It was not intended that if the distributor and trader had previously agreed to exchange information to which a newly publicised EIEP relates in a particular way, that the previous agreement reached by the parties would excuse the parties from complying with the (newly publicised) EIEP for the purposes of clause 12A.14(2). Rather, the publicising by the Authority of an EIEP for the first time was intended to "override" any such existing agreement.</p> <p>However, it is arguable that the effect of clause 12A.14(2) is that if the Authority publicises an EIEP under clause 12A.14(1), but the parties to a use-of-system agreement had previously agreed to exchange information to which the EIEP relates in another way, the parties are excused from complying with the newly publicised EIEP.</p> <p>The Authority considers that clause 12A.14 should be amended to make it clear that a distributor and trader may agree to exchange information other than in accordance with an EIEP, but only after the EIEP has been publicised.</p> <p>The Authority also considers that clause 12A.14 should be amended to make it clear that if the Authority publicises an amendment to an</p>

	<p>EIEP – including a new version of the EIEP – any existing agreement by the parties to a use-of-system agreement to not comply with the EIEP is not affected by the publicising of the amendment.</p>
Proposal	<p>The proposal is to amend clause 12A.14 so that it provides that:</p> <ul style="list-style-type: none"> • a distributor and trader must comply with an EIEP publicised by the Authority (existing subclause (1)) • a distributor and trader may agree to exchange information other than in accordance with an EIEP, but only after the EIEP has been publicised, and only if the agreement comes into effect on or after the date on which the EIEP comes into effect (new subclauses (2) and (3)) • if the parties agree to exchange information other than in accordance with an EIEP, and the Authority subsequently publishes an amendment to the EIEP (which would include a new version of an EIEP), the agreement is not affected by the publicising of the EIEP (new subclause (4)) • clause 12A.14 does not apply in respect of a voluntary EIEP (previously subclause (2)(b), now subclause (5)).
Proposed Code amendment	<p>12A.14 Distributors and traders must comply with EIEPs</p> <p>(1) If the Authority has publicised an EIEP under clause 12A.13, the distributor and the trader must, when exchanging information to which the EIEP <u>relates</u> applies, comply with the EIEP from the date on which the EIEP comes into effect.</p> <p>(2) Subclause (1) does not apply –</p> <p>(a) if –</p> <p>(i) the distributor and trader agree to exchange the information in any other way; and</p> <p>(ii) that agreement is recorded in the use-of-system agreement between the distributor and the trader;</p> <p>or</p> <p>(b) to an EIEP publicised under clause 12A.15.</p> <p>(3) <u>However, a distributor and a trader may, after an EIEP has been publicised, agree to exchange information other than in accordance with the EIEP, by recording the agreement in each use-of-system agreement between the distributor and trader.</u></p> <p>(4) <u>An agreement to exchange information other than in accordance with an EIEP is not effective in relieving a distributor and a trader of the obligation to comply with subclause (1), unless the agreement comes into effect on or after the date on which the relevant EIEP comes into effect.</u></p>

	<p>(5) <u>An agreement under subclause (3) is not affected by the Authority publicising an amendment to the EIEP.</u></p> <p>(6) <u>Subclause (1) does not apply to an EIEP publicised under clause 12A.15.</u></p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the promotion of competition in and the efficient operation of the electricity industry. The proposed amendment would do that by requiring the parties to use standardised ways to exchange information. The parties would only agree to exchange information in a way other than as provided in an EIEP if it would be more efficient for both parties. By providing for standardised information exchange, the Authority expects that barriers to retail entry would be lowered, as new entrant retailers could expect a more standardised approach across multiple networks.</p> <p>Accordingly, the proposed amendment is also desirable to promote competition in the electricity industry in accordance with section 32(1)(a) of the Act, and the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the costs and benefits of this proposed amendment. Accordingly, a qualitative assessment has been undertaken (see below).
Regulatory Statement	
Objectives of the	The objective of the proposal is to contribute to the promotion of

proposed amendment	competition in, and the efficient operation of, the electricity industry by requiring parties to use standardised ways to exchange information.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority considers the primary cost of the proposed Code amendment would be where changes were required to existing use-of-system agreements because the parties to the agreement wished to exchange information in a manner other than in accordance with a mandatory EIEP.¹⁵</p> <p>On a per-agreement basis, this cost could range from being negligible to being several thousand dollars. Parties whose use-of-system agreement already specified an alternative way of transferring data would just have to change the date of their agreement in order to comply with the proposed amendment. Parties whose use-of-system agreement did not specify an alternative way of transferring data would need to amend the agreement.</p> <p>The Authority's expectation is that parties who do not want to exchange information in accordance with an EIEP would have recorded this in their use-of-system agreement. Hence, the Authority expects that the cost of the proposed amendment would be minimal.</p> <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment is that it would require traders and distributors to give due consideration to whether their existing way of exchanging information was more efficient than using a newly publicised EIEP. Traders and distributors would be expected to only agree to exchange information in a way other than as provided for in an EIEP if it was more efficient for both parties. This promotes the efficient operation of the electricity industry and, through lowering retailers' cost-to-serve, promotes retail competition.</p> <p>A secondary benefit of the proposed amendment (proposed new clause 12A.14(4)) is that it would reduce transaction costs in instances where parties to a use-of-system agreement were amending the agreement following an amendment to a mandatory EIEP. It is not intended that parties should have to do this. To the extent that they are, this is an unnecessary cost.</p>

¹⁵ Currently EIEP 1, EIEP 2, EIEP 3 and EIEP 12 are mandatory.

	<p>Lastly, the proposed amendment would eliminate the current confusion and debate amongst some participants as to the intent of clause 12A.14. This would represent a further reduction in industry transaction costs.</p> <p><u><i>Net benefit</i></u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposal is the status quo. If this option were pursued, the benefits outlined above would not eventuate. Accordingly, the Authority is satisfied that the proposal is the best alternative.</p>

Publication of code breach reports from the reconciliation manager: clause 15.33

Reference number(s)	069-017
Issue	<p>Under clause 15.30(1), the reconciliation manager must provide a written report to the Authority setting out the number and details of any alleged breaches of the Code that it is aware of. The reconciliation manager must provide this report as soon as possible after it has provided reconciliation information for a consumption period, but by no later than 1pm on the second business day after it has provided the reconciliation information for the consumption period. In practice, the reconciliation manager sometimes provides this report to the Authority at the end of the first business day after it has provided reconciliation information for a consumption period.</p> <p>Clause 15.33 requires the Authority to publish the sections of this report that relate to any alleged breaches of the Code by the reconciliation manager by 9.30am the day after the Authority receives the report.</p> <p>If the reconciliation manager provides this report at the end of the first business day (rather than on the second business day), it is administratively difficult for the Authority to publish the relevant sections of the report by 9.30am on the following day.</p>
Proposal	<p>The proposal is to extend the timeframe within which the Authority must publish the relevant sections of the report, to give the Authority at least 2 full business days.</p> <p>This aligns with the reconciliation manager's obligation under clause 15.30 to provide its report to the Authority within two business days.</p>
Proposed Code amendment	<p>15.33 The Authority publishes reports By 0930-1630 hours on the <u>2nd</u> business day following the day on which the Authority receives the report of the reconciliation manager in accordance with clause 15.30, the Authority must publish the sections of the report that relate to an alleged breach of this Code by the reconciliation manager (if any).</p>
Assessment of proposed Code amendment against the	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Amending the obligations in the manner proposed would</p>

Authority's objective and section 32(1) of the Act	<p>reduce the Authority's operational costs.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	A quantitative cost benefit analysis has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of this proposal is to introduce a more realistic timeframe into the Code. This would mean that the Authority can comply and the Authority will publish the relevant sections of the reconciliation manager's Code breach report when participants expect them to be published.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed Code amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants. The information published by the Authority does not form part of any market process. It is only for participants' information.</p> <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment is that it would reduce the Authority's administrative costs. The Authority estimates</p>

	<p>this to be approximately \$500 per annum, which equates to a present value of approximately \$4,200 (assuming a 15 year discount period and a real discount rate of 8%).</p> <p><u><i>Net benefit</i></u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment would outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>An alternative would be the status quo which would not achieve the objectives of the proposed amendment.</p> <p>A further alternative would be to require the Authority to publish by 1630 hours on the first business day after it receives the report of the reconciliation manager. This would go some way towards resolving the administrative difficulty faced by the Authority. However, the Authority is of the view that in some cases this deadline might be difficult to meet and accordingly, prefers the proposal.</p>

NZDT Adjustment techniques: Clause 15.36(3)

Reference number(s)	070-018
Issue	<p>Clause 15.36(3) outlines the New Zealand Daylight Savings Time adjustment technique that must be used by:</p> <ul style="list-style-type: none"> • participants that provide submission information to the reconciliation manager • the reconciliation manager when providing reconciliation information to participants • participants that exchange information with other participants, if that information contains trading period specific data. <p>Clause 15.36(3) requires that the parties indicated above use the following codes in the data transfer file:</p> <ul style="list-style-type: none"> • “TPR” when the “trading period run on technique” is used; and • “TPM” when the “trading period move technique” is used. <p>However, the EIEP3 file format currently specifies that relevant participants must use a method that is equivalent to the TPR adjustment technique. However, the file format does not require the participant to use the TPR code in the data transfer file (ie EIEP3 does not provide a field for adjustment technique codes). Therefore such codes cannot be included in participants' data transfer files, which is a breach of the Code.</p> <p>The Authority has considered how best to resolve this issue, and has concluded that the best approach is to remove the option of using the TPM adjustment technique. The Authority believes this is the best approach because:</p> <ul style="list-style-type: none"> • of the costs associated with amending EIEP3 to provide for both codes in the data transfer file • the Authority understands no participants use the TPM adjustment technique. <p>With the proposed amendment in place, it would be unnecessary to require participants to use a code to indicate which adjustment technique they have used, because there would only be one technique available.</p>
Proposal	The proposal is to amend clause 15.36 to remove the TPM

	technique as an option.
Proposed Code amendment	<p>15.36 New Zealand Daylight Time adjustment techniques</p> <p>(1)...</p> <p>(2)...</p> <p>(3) A Daylight savings adjustments must be made by using 1 of the following techniques: (a) the “trading period run on technique” must be applied if the which requires that daylight saving adjustment periods are allocated as consecutive trading periods within the relevant day, in the sequence that they occur. The code “TPR” must be used within the data transfer file when this technique is used.; (b) the “trading period move technique” must be applied if the daylight saving adjustment periods are appended as additional trading periods at the end of the relevant day. The code “TPM” must be used within the data transfer file when this technique is used.</p> <p>(4) If no adjustment is made in accordance with subclause (3) to information exchanged between reconciliation participants that contains trading period specific data, the code “NZST” must be used within the data transfer file.</p>
Assessment of proposed Code amendment against the Authority’s objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Clarifying the process and obligations with regards to the adjustment technique for daylight savings in the manner proposed would reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority’s statutory objective and the requirements set out in section 32(1) of the Act.</p>

Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	A quantitative assessment of the proposal's costs and benefits has been undertaken (see below).
Regulatory Statement	
Objectives of the proposed amendment	The objective of the proposal is to improve the efficient operation of the electricity industry by removing an obligation that participants are unable to comply with, because of the format of EIEP3.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority does not expect the proposed amendment to place additional costs on industry participants. The Authority is not aware of any participants that use the TPM adjustment technique. Staff understand that all participants use the TPR adjustment technique.</p> <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment would be avoiding the cost of:</p> <ul style="list-style-type: none"> • amending EIEP3 to provide a field for adjustment technique codes • participants making the necessary system changes to accommodate the new field for the TPM and TPR codes. <p>The Authority estimates the cost of amending EIEP3 would be approximately \$30,000. This estimate comprises:</p> <ul style="list-style-type: none"> • approximately \$5,000 of cost the Authority would incur developing and consulting on an amended EIEP3 • approximately \$25,000 of cost that 10-15 traders and distributors would incur in making submissions on the

	<p>proposed amendment to EIEP3.</p> <p>The Authority estimates the cost of amending participants' systems to accommodate the revised EIEP3 could range between approximately \$10,000-\$50,000 per participant.¹⁶</p> <p>There is expected to be no corresponding benefit to requiring participants to comply with the Code because participants are already using the TPR adjustment technique.</p> <p><u>Net benefit</u></p> <p>On the basis of the above analysis the Authority considers the proposed amendment would have a positive net benefit.</p>
<p>Evaluation of alternative means of achieving the objectives of the proposed amendment</p>	<p>The alternative options are the status quo, and changing formats to include fields for both the TPM and TPR adjustment techniques. The Authority is satisfied that the proposal is the best alternative, for the reasons set out below.</p>
	<p>Option One: Status quo</p> <p>The status quo would mean that participants cannot comply with the obligations in the Code as they are unable to use the TPR and TPM codes within EIEP3 to indicate the adjustment technique used.</p>
	<p>Option Two: Change formats to include fields for TPM and TPR</p> <p>Changing formats is an expensive option, and given that the Authority is not aware of any participants using the TPM adjustment technique, it is not clear that the additional cost would provide any extra benefit than the proposed amendment.</p>

¹⁶ The participants affected would be traders, local networks and embedded networks.

Certification of reconciliation participants – clause 15.38

Reference number(s)	071-019
Issue	<p>Clause 15.38(1) provides that a reconciliation participant must obtain and maintain certification under Schedule 15.1 to perform a range of functions. To obtain certification, reconciliation participants must provide an audit report to the Authority (under clause 5 of Schedule 15.1).</p> <p>The Authority must be satisfied, on the basis of the audit report, that a reconciliation participant meets the requirements relevant to the functions for which the reconciliation participant seeks certification. If the reconciliation participant can demonstrate to the Authority that it has been performing the relevant functions successfully (even for a short period), it gives the Authority more confidence in certifying a new reconciliation participant.</p> <p>Currently, the Authority often allows a three month “grace period” before it certifies reconciliation participants. The three month period enables new reconciliation participants to demonstrate to the Authority that they can successfully perform the functions listed in clause 15.38(1) and that the Authority should therefore certify them. The Authority is only able to allow this grace period by granting exemptions to new reconciliation participants.</p> <p>In addition, in relation to generator switching, clause 15.38(1)(a) refers to “embedded generator” switching. This is an error and should be a reference to the more general “generator” switching.</p>
Proposal	<p>The proposal is to:</p> <ul style="list-style-type: none"> (a) add a new subclause to clause 15.38 allowing a reconciliation participant to perform the functions in subclause (1) without certification during the first 3 months of becoming active in the industry as a reconciliation participant. The 3 month grace period would begin from the date on which a reconciliation participant first performs a function listed in clause 15.38(1) (b) revoke clause 15.38(2) because it is unnecessary and would conflict with the proposed new subclause referred to above (c) revoke clause 2 of Schedule 15.1, because it is no longer necessary in light of the new subclause proposed above and it currently causes confusion.

<p>Proposed Code amendment</p>	<p>15.38 Functions requiring certification</p> <p>(1) A reconciliation participant (except an embedded generator selling electricity directly to another reconciliation participant) must obtain and maintain certification in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:</p> <ul style="list-style-type: none"> (a) maintaining registry information and performing customer and embedded generator switching (except if the maintenance of registry information is carried out by a distributor in accordance with Part 11): (b) gathering and storing raw meter data: (c) creating and managing (including validating, estimating, storing, correcting and archiving)— <ul style="list-style-type: none"> (i) half hour volume information; or (ii) non half hour volume information; or (iii) half hour and non half hour volume information; or (iv) dispatchable load information: (d) calculation of the number of ICP days and delivery of a report under clause 15.6: (da) delivery of electricity supplied information under clause 15.7: (db) delivery of information from retailer and direct purchaser half hourly metered ICPs under clause 15.8: (e) provision of submission information for reconciliation: (f) provision of metering information to the pricing manager in accordance with subpart 4 of Part 13. <p>...</p> <p>(2) To avoid doubt, the performance of any of the functions in subclause (1) by a reconciliation participant, or its agent or agents, without the reconciliation participant having certification, is a breach of this Code by the reconciliation participant.</p> <p>(3) <u>Despite subclause (1), a reconciliation participant does not breach this clause by performing a function specified in subclause (1) without having obtained certification if the reconciliation participant performs the function during the period that ends 3 months after the date on which the reconciliation participant first performed a function specified in subclause (1).</u></p> <p style="text-align: right;">Schedule 15.1</p>
--------------------------------	---

	<p>...</p> <p>2 — Requirement for certification</p> <p>Despite anything else in this Code, a reconciliation participant who is required to obtain certification under clause 15.38 must obtain certification in accordance with this Schedule no later than 3 calendar months after the date on which that reconciliation participant becomes a reconciliation participant in accordance with this Code.</p> <p>...</p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Allowing new reconciliation participants a "grace period" to perform the functions listed in clause 15.38(1) would enable the Authority to have a greater degree of confidence in granting certification that the reconciliation participant meets the relevant requirements. This would lead to greater operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a qualitative analysis assessment has been undertaken (see below).
Regulatory Statement	

Objectives of the proposed amendment	<p>The objectives of the proposal are to improve the efficient operation of the electricity industry by enabling the Authority to have a greater degree of confidence that new reconciliation participants meet the relevant requirements before granting certification.</p>
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority does not expect the proposed amendment to place additional costs on industry participants. However, if it did, they would be negligible. This is because the proposed amendment reflects current industry practice.</p> <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment is that it would reduce the transaction costs associated with new reconciliation participants entering New Zealand electricity markets. This is because the proposal would reduce the need for the Authority to grant exemptions that permit new reconciliation participants to operate in one or more electricity markets before being certified.</p> <p><u>Net benefit</u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposal would be the status quo. The status quo would mean that new reconciliation participants would only be able to obtain certification as required by clause 15.38 by providing an audit report based on test data. This is less meaningful for the Authority's decision making, and makes the process slower and less valuable.</p> <p>Accordingly, the Authority is satisfied that the proposed amendment is the best alternative.</p>

Publishing lists of certified reconciliation participants: clause 6 of Schedule 15.1

Reference number(s)	072-020
Issue	<p>Clause 6(a) of Schedule 15.1 requires the Authority to publish a list of certified reconciliation participants and "the period for which each reconciliation participant is certified". Those words are ambiguous as to whether the Authority must publish both the commencement date and expiry date of the certification period. The Authority considers that it should only be required to publish the expiry date of the certification period because the certification expiry date is the only piece of information the participant needs to determine when it should make its next application for certification.</p> <p>Clause 6(b) also requires the Authority to publish a list of the agents that reconciliation participants use. The Authority considers that list to no longer be required because nobody uses it, it is not a comprehensive list, and in fact participants could misinterpret its effect. The Authority no longer publishes the list.</p>
Proposal	<p>Amend clause 6 of Schedule 15.1 to require the list of certified reconciliation participants to include the date on which the certification of each reconciliation participant expires.</p> <p>Revoke paragraph (b), to remove the Authority's obligation to publish a list of the agents used by certified reconciliation participants.</p>
Proposed Code amendment	<p>6 Lists of certified reconciliation participants and agents The Authority must publish, and keep updated—</p> <p>(a) a list of certified reconciliation participants; <u>that includes, for each reconciliation participant, the date on which the certification expires.</u> and the period for which each reconciliation participant is certified; and</p> <p>(b) a list of agents used by certified reconciliation participants. <u>[Revoked]</u></p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. It would clarify the obligation regarding the list of certified reconciliation participants and remove the unnecessary compliance cost of publishing the list of agents.</p> <p>Accordingly, the proposed amendment is also desirable to promote</p>

Act	<p>the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>A qualitative assessment has been undertaken (see below).</p>
Regulatory Statement	
Objectives of the proposed amendment	<p>The objectives of the proposal are to:</p> <ul style="list-style-type: none"> (a) clarify that the published list of reconciliation participants only need to state the date on which certification of each reconciliation participant expires (b) remove the Authority's obligation to publish a list of the agents used by certified reconciliation participants.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants. One of the reasons why the Authority considers the list of agents that reconciliation participants use is no longer required is because nobody uses it.</p> <p><u>Benefits</u></p>

	<p>The benefit of implementing the proposed amendment would be avoiding the unnecessary cost of a change to the Authority's retail audit database to comply with the Code requirement to manage and publish the list of agents that reconciliation participants use. The Authority estimates that the system changes could cost up to \$50,000, based on the Authority's experience with previous changes to the database. As noted above, this cost would not deliver any benefits because participants do not use the list.</p> <p><u><i>Net benefit</i></u></p> <p>On the basis of the above analysis the Authority considers the proposed amendment would have a positive net benefit.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>An alternative would be the status quo which would not achieve the objectives of the proposed amendment.</p> <p>A further alternative would be to also require the list to include the commencement dates of the certification of each reconciliation participant. That is not preferred because a reconciliation participant will always be certified when it is included on the list, so there is no general need to know when each certification commenced.</p>

Quantification error: clauses 3 and 14 of Schedule 15.2

Reference number(s)	074-021
Issue	<p>Clause 14 of Schedule 15.2 relates to quantification errors and metering interrogation systems.</p> <p>Clause 14 has no effect because it does not place an obligation on any participant. It only requires that an unnamed party ensure that obligations already imposed elsewhere in the Code are complied with. In addition, it includes a cross-reference to clause 38(1) of Schedule 10.7, which should be a cross-reference to clauses 4(1), 4(2), and 4(3) of Schedule 10.7).</p> <p>However, Schedule 15.2 should place an obligation on reconciliation participants in respect of raw meter data used to derive volume information in accordance with the Schedule. Specifically, Schedule 15.2 should include a clause requiring that, when a reconciliation participant collects raw meter data, it must not round or truncate data provided by the meter.</p> <p>This is because, where compensation factors are required to convert the meter readings contained in raw meter data to volume information, any rounding or truncating of the meter readings may have a material impact on the accuracy of the volume information.</p> <p>The Authority considers that this obligation should be inserted in clause 3 of Schedule 15.2.</p>
Proposal	<p>It is proposed that:</p> <ul style="list-style-type: none"> • clause 14 of Schedule 15.2 be revoked • clause 3 of Schedule 15.2 be amended to insert a new subclause that states that any raw meter data used to derive volume information must be used to the number of decimal places recorded by each meter, and must not be rounded or truncated from the data provided by the meter.
Proposed Code amendment	<p>Amend clause 3 of Schedule 15.2 by inserting a new subclause (5) as follows:</p> <p><u>(5) A reconciliation participant must ensure that all raw meter data used to derive volume information in accordance with this Schedule is used to the number of decimal places recorded by each meter, and is not rounded or truncated from the raw meter</u></p>

	<p><u>data provided by the meter.</u></p> <p>Revoke clause 14 of Schedule 15.2:</p> <p>14 Quantification error</p> <p>The design of the interrogation system must ensure that the requirements of clause 38(1) of Schedule 10.7 are complied with.</p>
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it will contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p> <p>Refer to the analysis under the Regulatory Statement section below.</p>
Regulatory Statement	
Objectives of the proposed	<p>The objective of the proposal is to contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner</p>

amendment	proposed would reduce confusion in this area, leading to improved operational efficiency.
Evaluation of the costs and benefits of the proposed amendment	<p>The Authority considers that the proposed amendment would have a positive net benefit.</p> <p><u>Costs</u></p> <p>The Authority expects the proposed amendment to place no additional costs on industry participants. However, if it did, they would be negligible. This is because the proposed amendment reflects current industry practice.</p> <p><u>Benefits</u></p> <p>The primary benefit of the proposed amendment is that it would clarify the obligation on traders to provide accurate data to the reconciliation manager. If the data is rounded or similar, it results in higher unaccounted-for-energy, which means that the marginal value consumers place on the electricity they purchase is not as close to the cost of producing that electricity as it could be. This is a market inefficiency. In some circumstances the errors could be reasonably material (eg, volume information collected from large metering installations).</p> <p><u>Net benefit</u></p> <p>Based on the above analysis, the Authority is satisfied that the benefits of the proposed amendment would outweigh the costs.</p>
Evaluation of alternative means of achieving the objectives of the proposed amendment	<p>The only alternative to the proposal is the status quo. If this option were pursued, the benefits outlined above would not eventuate. For example, there would be a risk that traders may round or truncate raw meter data with the effect that the information would not be accurate. Accordingly, the Authority is satisfied that the proposal is the best alternative.</p>

Appendix C “Minor” amendments

Definition of approved test house: clause 1.1(1)

Reference number(s)	003-022
Issue	The current definition of an approved test house incorrectly states that a test house is a meter testing facility. However test houses, in the context of the Code, are actually facilities where the calibration and certification of metering installations and metering components are undertaken.
Proposal	The proposal is to amend the definition of approved test house to describe correctly the activities undertaken by a test house in the context of the Code – i.e. calibration and certification, not testing.
Proposed Code amendment	approved test house means a meter testing and calibration facility that has been approved by the Authority in accordance with Part 10 to do one or more of the following: <u>(a) calibrate metering installations or metering components:</u> <u>(b) certify metering installations or metering components</u>
Grounds for not consulting	The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act. This is because the proposed amendment would have no effect on the activities that approved test houses do, or can do, under the Code, and there will be no effect on the obligations of participants. Rather, the proposed amendment ensures that the definition is correct and reflects reality.
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying what an approved test house does in the manner proposed would reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs. Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act. The proposed amendment would have no effect on competition or reliability.

Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed Code amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Definition of EIEP: clause 1.1(1)

Reference number(s)	081-023
Issue	<p>EIEP is defined in Part 1 as meaning “an electricity information exchange protocol that sets out standard formats for the exchange of information between distributors and traders”.</p> <p>The Authority intends to publish an EIEP to specify the format in which retailers must provide information to consumers under clause 11.32B. The Authority proposes to publish an EIEP, as EIEPs are a format that retailers well understand.</p> <p>Clause 11.32B comes into force on 1 February 2016. It will require retailers to comply with procedures publicised by the Authority under clause 11.32F when providing information to a consumer about the consumer's electricity consumption. The procedures will specify the formats in which such information is to be provided.</p> <p>The Authority therefore proposes to amend the definition of EIEP so that EIEPs can also regulate the exchange of information between, or the provision of information by, participants other than distributors and traders.</p> <p>The Authority also proposes to amend new clauses 11.32B and 11.32F so that those clauses refer to both the publication of procedures and the publication of EIEPs (which will set out the format for retailers to provide information to consumers).</p>
Proposal	<p>The proposal is to:</p> <ul style="list-style-type: none"> • amend the definition of EIEP to remove reference to EIEPs relating to distributors and traders only: • amend the definition of EIEP to reflect that EIEPs set out standard formats for the provision of information by participants, as well as the exchange of information between participants: • with effect from 1 February 2016: <ul style="list-style-type: none"> ○ amend new clause 11.32B(2) to make it clear that a retailer must comply with the procedures and any relevant EIEP publicised by the Authority under clause 11.32F: ○ amend clause 11.32F to make it clear that the Authority must publish procedures that specify the manner in which retailers must give information to consumers and 1 or more EIEPs that

	set out formats in which retailers must give information to consumers.
Proposed Code amendment	<p>Amend the definition of EIEP as follows:</p> <p>EIEP means an electricity information exchange protocol that sets out standard formats for the exchange <u>or provision</u> of information between distributors and traders.</p> <p>From 1 February 2016, amend clause 11.32B(2) as follows:</p> <p>(2) In responding to a request, the retailer must comply with the procedures, <u>and any relevant EIEP, publicised</u> by the Authority under clause 11.32F.</p> <p>From 1 February 2016, amend clause 11.32F as follows:</p> <p>(1) The Authority must, no later than 20 business days after this clause comes into force, publicise (and must keep publicised)—</p> <p>(a) procedures under which a retailer must respond to a request from a consumer under clause 11.32B; <u>and</u></p> <p>(b) <u>1 or more EIEPs with which a retailer must comply when responding to such a request.</u></p> <p>(2) The procedures publicised by the Authority must—(a) specify the manner in which information must be given to consumers; <u>and</u></p> <p>(3)(b) <u>Each EIEP publicised by the Authority must specify 1 or more formats in which information must be given to consumers.</u></p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendments clarify that in addition to publicising procedures under clause 11.32F (which retailers must comply with under clause 11.32B), the Authority may also publicise EIEPs that specify formats for the provision of information by retailers to consumers. This is not a material change, because the amendment that comes into force on 1 February 2016 already enables the Authority to publicise procedures that specify formats in which information must be given to consumers. The proposal only clarifies that the formats will be EIEPs.</p>
Assessment of proposed Code	The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity

amendment against section 32(1) of the Act	<p>industry. The proposed amendment would achieve that by making it clear that the Authority may publicise both procedures and EIEPs that specify the format in which retailers must give information to consumers. That is important because EIEPs are a format that retailers well understand.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would allow the Authority to publish both procedures and EIEPs with which retailers must comply when giving information to consumers. EIEPs, which set out the formats in which participants must give information, are a format that retailers understand.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Definition of distributor: clause 1.1(1)

Reference number(s)	007-024
Issue	<p>Definition of "distributor"</p> <p>Distributor is defined in section 5 of the Electricity Industry Act 2010 as follows:</p> <ul style="list-style-type: none"> • distributor means a business engaged in distribution • distribution means the conveyance of electricity on lines other than lines that are part of the national grid <p>Distributor is defined in Part 1 of the Code as follows:</p> <p>distributor means as follows:</p> <ul style="list-style-type: none"> (a) except in Part 12A, and as provided in paragraphs (b) and (c), a participant who supplies line function services to another person; (b) in Parts 1 (except for the definitions of connection and operation standards, distribution network, and specified participant), 8, 10, 11, 12, 13, 14 and 15, a participant who owns or operates a local network; and— <ul style="list-style-type: none"> (i) in Part 8, includes a direct consumer; and (ii) in Parts 10, 11, 13, 14, and 15 includes an embedded network owner (c) for the purposes of the definitions of connection and operation standards, distributed generation and distribution network and Part 6, a participant who owns— <ul style="list-style-type: none"> (i) a local network; or (ii) an embedded network that is used to convey 5 GWh or more of electricity per annum; or (iii) a system of lines that— <ul style="list-style-type: none"> (A) is used for providing line function services to a person other than the owner of those lines; and (B) is not part of the grid and has no direct or indirect connection to the grid; and (C) conveys 5 GWh or more of electricity per annum <p>The definition of "distributor" in the Act and "distributor" in the Code are inconsistent. This causes confusion and is undesirable.</p> <p>In most places in the Code, the term "distributor" can be defined in accordance with the Act. In particular, it is unnecessary for the definition of "distributor" in the Code to specifically refer to</p>

	<p>participants that supply line function services (as in paragraph (a) of the definition of distributor). That is because, in practice, any business engaged in the conveyance of electricity on lines other than lines that are part of the national grid (as in the definition of "distribution" in the Act), will also be a business that, as in the definition of "line function services" in the Code:</p> <ul style="list-style-type: none"> • provides and maintains works for the conveyance of electricity; or • operates such works, including controlling voltage and assuming responsibility for losses of electricity. <p>Therefore, <i>"a participant who supplies line function services to another person"</i> is a distributor as defined in the Act.</p> <p>In addition, it is not necessary for the definition of "distributor" in the Code to specifically refer to embedded network owners (as in paragraph (b)(ii) of the definition of distributor). Embedded network owners are distributors, as defined in the Act, for the following reasons:</p> <ul style="list-style-type: none"> • the definition of the term "distribution" in the Act does not distinguish between local networks and embedded networks • the owner of an embedded network will also be a business engaged in distribution. <p>"Distributors" that own or operate local networks</p> <p>The Code should clearly specify the rights and obligations that relate only to distributors that own or operate local networks, and do not relate to distributors that own or operate embedded networks.</p> <p>The effect of the definition of "distributor" is that the obligations in Part 1 (except for the definitions of connection and operation standards, distribution network, and specified participant), Part 8, and Part 12 apply only to local network distributors. All other Parts of the Code either apply to both local network and embedded network distributors, or do not apply to distributors at all. This is explained later in this document.</p> <p>Accordingly, in Part 12, the term "distributor" should be replaced with another term – the Authority recommends "local network distributor".</p> <p>However, the Authority does not consider it appropriate to replace the term "distributor" with "local network distributor" in either Part 1 or</p>
--	--

	<p>Part 8 (in which a "distributor" also includes a direct consumer), for the reasons set out below.</p> <p><i>"Distributor" for the purposes of Part 1</i></p> <p>The Authority has reviewed each use of the term "distributor" in Part 1 and is satisfied that, in each place, the term "distributor" does not refer only to local network distributors. Accordingly, it is appropriate that the term "distributor" should have the meaning set out in section 5 of the Act wherever it appears in Part 1.</p> <p>As a consequence of this proposed amendment, the definition of "line function services" in Part 1 needs to be amended to remove the reference to the definition of "distributor", seeing as the definition of "distributor" will no longer include the words "line function services". The Authority also considers that the definition of "line function services" should refer to the definition of the same term in section 5 of the Act, which states that "line function services" has the meaning given in section 2(1) of the Electricity Act 1992. The definitions of "line function services" in the Code and in the Electricity Act 1992 are identical.</p> <p>The Authority also considers that the reference to Part 12A in the definition of "line function services" should be removed, because the term "line function services" should have the meaning in the Act in all parts of the Code where it appears. The only parts of the Code other than Part 12A in which the term "line function services" appears are Part 11 (in clauses 11.5(2) and 11.16(a)), and in Part 1 (in the definition of "distributor", which the Authority is proposing to amend so that it does not include a reference to line function services).</p> <p>The definition of "lines" in Part 1 should also be amended to remove the reference to the definition of "distributor", as the definition of "distributor" will no longer include the word "lines". The Authority also considers that the definition of "lines" should refer to the definition of "lines" in section 5 of the Act, which has the same meaning as "lines" in the Code. The Authority also proposes removing the references to the definition of distribution network and Part 6 from the definition of "lines" because the term "lines" has the same, defined meaning wherever that term appears in the Code. That is because:</p> <ul style="list-style-type: none"> • in the definition of distribution network, distributor, and Part 6,
--	--

	<p>"lines" has the defined meaning in the Code;</p> <ul style="list-style-type: none"> • in all other places in the Code, "lines" has the defined meaning in the Act. That is because clause 1.1(2) of the Code provides that any term defined in the Act and used, but not defined, in the Code has the same meaning as in the Act; and • the definition of "lines" in the Act and in the Code have the same meaning. <p><i>"Distributor" for the purposes of Part 8</i></p> <p>Currently, the definition of distributor in the Code provides that for the purposes of Part 8, a distributor is a participant who supplies line function services to another person (paragraph (a)), who owns or operates a local network (paragraph (b)), and includes a direct consumer (subparagraph (b)(ii)). The Code defines a direct consumer as <i>"a consumer with a point of connection to the grid"</i>. "Distributor", for the purposes of Part 8, does not include an embedded network owner.</p> <p>The Authority proposes to add a new definition of "connected asset owner", which would mean "a local network distributor or a direct consumer". All references to "distributor" in Part 8 would then be replaced with a reference to "connected asset owner". That would ensure that both the relevant type of distributor, and direct consumers, would continue to be subject to the obligations in Part 8.</p> <p>The Authority also proposes a small amendment to clause 6 of Technical Code A in Schedule 8.3. The clause is titled "Specific requirements for local networks". However, because the clause as currently drafted places obligations on "distributors", which for the purposes of Part 8 includes direct consumers, and that will remain the position if the proposal to add the definition of "connected asset owner" to the Code proceeds, the clause should be titled "Specific requirements for connected asset owners".</p> <p>"Distributors" that own or operate local or embedded networks</p> <p>Apart from Part 12 (for which the Authority proposes replacing "distributor" with "local network distributor"), there are no other parts of the Code that should apply only to distributors that own or operate local networks. The definition of "distributor" provides that the obligations in Part 10, 11, 13, 14, and 15 apply to distributors who own or operate local networks or embedded networks. Accordingly,</p>
--	--

	<p>it is appropriate that the term "distributor" as it is used in those Parts has the meaning of "distributor" set out in section 5 of the Act (which includes both local and embedded network distributors).</p> <p>With regard to Part 12A, paragraph (a) of the definition of distributor provides that the definition of "distributor" does not apply in respect of Part 12A. Clause 1.1(2) of the Code provides that <i>"any term that is defined in the Act and used, but not defined in this Code, has the same meaning as in the Act."</i></p> <p>Because there is no definition of "distributor" in the Code for the purpose of Part 12A, the effect of clause 1.1(2) of the Code is that "distributor" in Part 12A has the meaning in section 5 of the Act. The Authority considers that should remain the position.</p> <p>The term "distributor" is not used in Parts 2 to 5, 7, or 14A and amendments are not required to Part 16 (revoked) or Part 17.</p> <p>"Distributors" that own or operate 'islanded networks'</p> <p>Networks that are not directly or indirectly connected to the grid are known as 'islanded networks' – examples of islanded networks are Haast Network, Milford Sounds, Stewart Island, Chatham Islands, and Scott Base.</p> <p>A person that owns or operates an islanded network is a "distributor" for the purposes of the Act. That is because the Act defines "distributor" as a business engaged in distribution, and "distribution" means the conveyance of electricity on lines other than lines that are part of the national grid. That includes lines that are part of an islanded network.</p> <p>At present, distributors that own or operate islanded networks are required to comply with the obligations of distributors in Part 6, Part 9, and Part 12A of the Code. That is because:</p> <ul style="list-style-type: none"> • Part 6: paragraph (c)(iii) of the definition of distributor provides that for the purposes of Part 6, a distributor includes a participant that owns a system of lines used to provide line function services that is not part of the grid and has no direct or indirect connection to the grid (i.e an islanded network). Part 6 is discussed further below. • Part 9: The term "distributor" is not used in Part 9. However, the term "specified participant", which is used throughout Part 9, is defined in Part 1 as including a "distributor". Paragraph (b) of the
--	---

	<p>definition of “distributor” expressly states that the definition of "distributor" in that paragraph does not apply in respect of the definition of "specified participant". Accordingly, for the purposes of Part 9, "distributor" has the meaning in paragraph (a) of the definition; ie a distributor is <i>"a participant who supplies line function services to another person"</i>. Such participants include participants that own islanded networks.</p> <ul style="list-style-type: none"> • Part 12A: For the reasons set out above, "distributor", when used in Part 12A, has the meaning of "distributor" given in the Act. Because the Act definition includes islanded network owners and operators, the owner or operator of an islanded network must comply with the obligations of distributors in Part 12A. <p>Distributors that own or operate islanded networks are not required to comply with any other Parts of the Code. That is because for the purposes of Parts 1 (except for definitions that relate specifically to Parts 6 and 9), 8, 10, 11, 12, 13, 14, and 15, a distributor is a participant that owns or operates a local network (and, in some cases, an embedded network) – the owners and operators of islanded networks are excluded from the definition. As noted above, the term "distributor" is not used in Parts 2 to 5, 7, or 14A.</p> <p>Accordingly, in order to retain the status quo in respect of the regulation of distributors that own or operate islanded networks, the Authority proposes inserting a new clause in the Code that provides that except in Parts 6, 9, and 12A, nothing in the Code applies to a distributor in respect of its distribution activities that are conducted on an islanded network.</p> <p>"Distributor" for the purposes of Part 6 (and obligations of "distributed generators")</p> <p>Subparagraphs (c)(i), (ii), and (iii) of the definition of "distributor" provide that for the purposes of Part 6 (and various definitions in the Code), a distributor is a participant that owns a local network, an embedded network that conveys 5 GWh or more of electricity per annum, or an islanded network that conveys 5 GWh or more of electricity per annum.</p> <p>Because, for the purposes of Part 6, a distributor can include a local network owner and an embedded network owner, the Authority considers it is appropriate that the term "distributor" as it is used in</p>
--	--

Part 6 also has the meaning of "distributor" set out in section 5 of the Act.

However, further amendments to the Code are required to make it clear that the connection of distributed generation is not regulated if the distributed generation is or will be connected to:

- an embedded network that conveys less than 5 GWh of electricity per annum (as is currently the case under subparagraph (c)(ii)), for the reasons discussed below under "embedded networks"; or
- an islanded network that conveys less than 5 GWh of electricity per annum (as is currently the case under subparagraph (c)(iii)), for the reasons discussed below under "islanded networks".

Embedded networks

As set out above, subparagraph (c)(ii) of the definition of "distributor" provides that for the purposes of Part 6, a distributor includes a participant who owns an embedded network that is used to convey 5 GWh or more of electricity per annum. Rather than specify this requirement in the definition of "distributor", the Authority considers that Part 6 should be amended to make it clear that such distributors are not required to comply with the obligations of distributors in Part 6.

The Authority also wants to make it clear that a distributed generator wishing to connect to an embedded network that is used to convey less than 5 GWh of electricity per annum does not have to comply with any obligations in Part 6. That is the current position under the Code because:

- a "distributed generator" is a person who owns/operates (or intends to own/operate) "distributed generation";
- "distributed generation" means generating plant that is "connected" or proposed to be "connected";
- "connected" means to electrically connect to a "distribution network" (or a consumer installation that is electrically connected to a "distribution network");
- "distribution network" means the electricity lines, and associated equipment, owned or operated by a "distributor"; and
- "distributor", for the purpose of the definition of "distribution

	<p>network", has the meaning in paragraph (c) of the definition, which provides that an embedded network owner is only a distributor for the purposes of Part 6 if the embedded network is used to convey 5 GWh or more of electricity per annum.</p> <p>The combined effect of the above definitions is that a person is a distributed generator for the purposes of Part 6 only if it wants to "connect" "distributed generation" to a "distribution network" owned by a "distributor" (which does not include embedded network owners if less than 5 GWh per annum is conveyed on the network).</p> <p>However, the Authority considers that the Code should make it clearer that a distributed generator wanting to connect to an embedded network that conveys less than 5 GWh per annum does not have to comply with any obligations in Part 6 in respect of that connection.</p> <p><i>Islanded networks</i></p> <p>As set out above, subparagraph (c)(iii) of the definition of "distributor" provides that for the purposes of Part 6, a distributor includes a participant that owns lines that are not part of the grid, and have no direct or indirect connection to the grid (i.e an islanded network), if the network conveys 5 GWh or more of electricity per annum.</p> <p>The Authority considers that Part 6 of the Code should make it clear that a distributor that owns or operates such an islanded network does not have to comply with the obligations of distributors in Part 6. Similarly, Part 6 should also be amended to make it clear that a distributed generator wishing to connect to such an islanded network does not have to comply with the obligations of distributed generators in Part 6.</p>
<p>Proposal</p>	<p>The proposal is to:</p> <ul style="list-style-type: none"> • amend the definition of "distributor" so that distributor has the meaning given to it in section 5 of the Act • add a new definition of "local network distributor", which means a distributor that owns or operates a local network • replace the word "distributor" with the words "local network distributor" in clause 1(1)(b) of Schedule 12.1 (which is the only place where the term "distributor" is used in Part 12)

	<ul style="list-style-type: none"> • add a new definition of "connected asset owner", which means a local network distributor or a direct consumer • replace the word "distributor" with the words "connected asset owner" in each place that the word "distributor" appears in Part 8 • amend the title of clause 6 of Technical Code A in Schedule 8.3 to read "Specific requirements for connected asset owners" • add a new clause 1.5A that provides that, except in Parts 6, 9, and 12A, nothing in the Code applies to a distributor in respect of its distribution activities that are conducted on an islanded network • add a new definition of "distribution" so that distribution has the meaning given to it in section 5 of the Act (which is necessary as the word "distribution" is used in the new clause 1.5A) • add new clauses to Part 6 that clarify that the obligations in Part 6 do not apply to: <ul style="list-style-type: none"> ○ distributors or distributed generators in respect of the connection of distributed generation to embedded networks or islanded networks that convey less than 5 GWh of electricity per annum; or ○ distributed generators that wish to connect to such networks • amend the definition of "line function services" to remove the references to the definition of "distributor" and Part 12A, and to refer to the definition of "line function services" in the Act • amend the definition of "lines" to remove the references to the definition of "distribution network", the definition of "distributor", and Part 6, and to refer to the definition of "lines" in the Act.
Proposed Code amendment	<p>Amend the following definitions in clause 1.1(1):</p> <p>distributor <u>has the meaning given to it by section 5 of the Act</u> means as follows:</p> <p>(a) except in Part 12A, and as provided in paragraphs (b) and (c), a participant who supplies line function services to another person;</p> <p>(b) in Parts 1 (except for the definitions of connection and operation standards, distribution network, and specified participant), 8, 10, 11, 12, 13, 14 and 15, a participant who owns or operates a local network; and —</p>

	<p>(i) in Part 8, includes a direct consumer; and</p> <p>(ii) in Parts 10, 11, 13, 14, and 15 includes an embedded network owner</p> <p>(c) for the purposes of the definitions of connection and operation standards, distributed generation and distribution network and Part 6, a participant who owns—</p> <p>(i) a local network; or</p> <p>(ii) an embedded network that is used to convey 5 GWh or more of electricity per annum; or</p> <p>(iii) a system of lines that—</p> <p>(A) is used for providing line function services to a person other than the owner of those lines; and</p> <p>(B) is not part of the grid and has no direct or indirect connection to the grid; and</p> <p>(C) conveys 5 GWh or more of electricity per annum</p> <p>line function services, for the purposes of the definition of distributor and in Part 12A, means the following: <u>has the meaning given to it by section 5 of the Act</u></p> <p>(a) the provision and maintenance of works for the conveyance of electricity;</p> <p>(b) the operation of such works, including the control of voltage and assumption of responsibility for losses of electricity</p> <p>lines <u>has the meaning given to it by section 5 of the Act</u>, for the purposes of the definition of distribution network, distributor, and Part 6, means works that are used or intended to be used for the conveyance of electricity</p> <p>Insert the following definitions in clause 1.1(1) in the appropriate alphabetical order:</p> <p><u>connected asset owner</u> means a local network distributor or a direct consumer</p> <p><u>distribution</u> has the meaning given to it by section 5 of the Act</p> <p><u>local network distributor</u> means a distributor that owns or operates a local network</p> <p>Insert a new clause 1.5A as follows:</p> <p><u>1.5A Application of Code to distributors</u></p> <p><u>Except in Parts 6, 9, and 12A, nothing in this Code applies to a distributor in respect of its distribution activities that are not</u></p>
--	--

conducted on a **network** that is—

- (a) directly **connected** to the **grid**; or
- (b) **connected** to the **grid** through 1 or more other **networks**.

Insert a new clause 6.2A as follows:

6.2A Application of Part to distributors in respect of embedded networks

Nothing in this Part applies to—

- (a) a **distributor** in respect of the **distributor's** ownership or operation of an **embedded network** that conveys less than 5 GWh of **electricity** per annum; or
- (b) a **distributed generator** when the **distributed generator** wishes to **connect** or has **distributed generation connected** to such an **embedded network**.

6.2B Application of Part to distributors in respect of systems of lines not directly or indirectly connected to the grid

Nothing in this Part applies to—

- (a) a **distributor** in respect of the **distributor's** ownership or operation of a system of **lines** that is used for providing **line function services** only to the **distributor**; or
- (b) a **distributor** in respect of the **distributor's** ownership or operation of a system of **lines**—
 - (i) that conveys less than 5 GWh of **electricity** per annum; and
 - (ii) that is not—
 - (A) directly **connected** to the **grid**; or
 - (B) **connected** to the **grid** through 1 or more other **networks**; or
- (c) a **distributed generator** when the **distributed generator** wishes to **connect** or has **distributed generation connected** to a system of **lines** described in paragraph (b).

Replace the word "distributor" with the words "connected asset owner" in each place that the word "distributor" appears in Part 8

Amend the title of clause 6 of Technical Code A of Schedule 8.3 as follows:

6 Specific requirements for ~~local networks~~ connected asset owners

	<p>Bold the word "lines" wherever it appears in the Code.</p> <p>Bold the words "line function services" in clauses 11.5(2) and 11.16(a).</p> <p>Amend clause 1 of Schedule 12.1 as follows:</p> <p>1 Categories of designated transmission customers required to enter into transmission agreements with Transpower</p> <p>(1) The categories of designated transmission customers required to enter into transmission agreements with Transpower are—</p> <p>(a) direct consumers that have a point of connection to the grid; and</p> <p>(b) local network distributors; and</p> <p>(c) generators that are directly connected to the grid.</p>
<p>Grounds for not consulting</p>	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial. The proposed amendments are intended to remove confusion and uncertainty created by the fact that the definitions of "distributor" in the Act and "distributor" in the Code are inconsistent. The insertion of the new definitions of "connected asset owner", "distribution", and "local network distributor", and the change to clause 1 of Schedule 12.1, are consequential on the change to the definition of "distributor", and are therefore technical and non-controversial. The amendment to the title of clause 6 of Technical Code A of Schedule 8.3 is technical and non-controversial because it is consequential on the insertion of the new definition of "connected asset owner".</p> <p>The addition of the new proposed clause 1.5A is necessary to retain the status quo, which is that except in Parts 6, 9, and 12A, distributors who own or operate islanded networks are not regulated under the Code.</p> <p>The addition of the new proposed clauses 6.2A and 6.2B is necessary to retain the status quo in respect of the connection of distributed generation to embedded networks and islanded networks that convey less than 5 GWh per annum.</p> <p>Amending the definitions of "line function services" and "lines" to refer to the definitions in the Act, and to remove reference to specific definitions and Parts in which those terms are used, is also technical and non-controversial. That is because both those terms have the same meaning in the Act as in the Code, and it is unnecessary and</p>

	undesirable for the Code to state that those terms only have the defined meaning when used in certain places in the Code.
Assessment of proposed Code amendment against the Authority's objective and section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it will contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed will reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve. As set out in the issues section, the definition of distributor in the Act and in the Code are different, which causes confusion about the obligations in the Code that apply to distributors. Amending the Code as proposed would resolve that confusion, and make it clear to distributors the provisions in the Code that they must comply with.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Definition of electricity supplied: clause 1.1(1)

Reference number(s)	083-025
Issue	There is confusion about whether the term 'electricity supplied' includes electricity that a retailer has supplied to an ICP for which the retailer is responsible without an arrangement in place with a consumer.
Proposal	<p>The proposal is to amend the definition of "electricity supplied" by:</p> <ul style="list-style-type: none"> removing the words "across points of connection to consumers" from the stem of the definition adding a further item to the non-exhaustive list in the definition, to include electricity a retailer has supplied despite having no arrangement with a consumer.
Proposed Code amendment	<p>electricity supplied means, for any particular period, the information relating to the quantities of electricity supplied by retailers across points of connection to consumers, sourced directly from the retailer's financial records, including quantities—</p> <ol style="list-style-type: none"> that are metered or unmetered; and supplied through normal customer supply and billing arrangements; and supplied under sponsorship arrangements; and supplied under any other arrangement; <u>and</u> <u>supplied at an ICP where there is no arrangement with a consumer</u>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment will have no impact on current practice, and will not have the effect of changing any participant's obligations. Rather, the proposed amendment would resolve a lack of clarity in the definition so as to avoid confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definition in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.

	<p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a lack of clarity in the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Definition of de-energisation: clause 1.1(1)

Reference number(s)	005-026
Issue	<p>The Code includes the following definitions:</p> <ul style="list-style-type: none"> • a definition of “de-energisation” that also defines the terms “de-energise” and “de-energised”; • a separate definition of “de-energise”; and • a definition of “energisation” that also defines “de-energise”, “de-energised”, and “de-energisation”. <p>These multiple definitions are unnecessary and confusing.</p>
Proposal	<p>The proposal is to remove the confusion about the meanings of de-energisation, de-energise, and de-energised by:</p> <ul style="list-style-type: none"> • deleting the separate definition of de-energise (which refers to the definition of energisation); and • amending the definition of energisation to remove the definitions of de-energise, de-energised and de-energisation. <p>The definition of de-energisation should also have commas surrounding the item "or the removal of any fuse or link", to mirror the drafting used in the definition of energisation.</p>
Proposed Code amendment	<p>de-energisation means the operation of any isolator, circuit breaker, or switch₂, or the removal of any fuse or link₂, so that no electricity can flow through a point of connection on a network, and de-energise and de-energised have corresponding meanings de-energise has the meaning given to it in the definition of energisation</p> <p>energisation means the operation of an isolator, circuit breaker, or switch, or the placing of a fuse or link, so that electricity can flow through a point of connection on a network, and—</p> <p>(a) energise and energised have corresponding meanings; and</p> <p>(b) de-energise means to reverse the process of energisation and de-energised and de-energisation have corresponding meanings</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment would resolve a drafting</p>

	error to avoid confusion, rather than having any impact on the practice of energisation or de-energisation of points of connection.
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definitions in the manner proposed will reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Definition of event date: clause 1.1 (definition primarily used in Schedule 11.3)

Reference number(s)	009-027
Issue	<p>The definition of event date refers to “the date on which an arrangement between a customer and a trader for the supply of electricity at the ICP comes into effect”.</p> <p>The term event date is only used in Part 11 of the Code, primarily in Schedule 11.3, which prescribes processes for switching ICPs from one trader (the losing trader) to another trader (the gaining trader). Such a switch is either the result of the gaining trader having an arrangement with the customer or embedded generator (ie signing up a new customer), or otherwise assuming responsibility for the ICP under clause 11.18(1). The switch occurs when the gaining trader begins trading electricity at the ICP or assumes responsibility for the ICP.</p> <p>It is clear from the provisions of Schedule 11.3 that the term "event date" refers to the date on which the switch occurs.</p> <p>However, the definition could be read to refer to the date on which the arrangement between the trader and the customer becomes a binding agreement. That interpretation is not the intended meaning of event date.</p> <p>Clause 2 of Schedule 11.3 refers to the date that "the arrangement with the customer or embedded generator comes into effect". In this context, this is the date on which the arrangement becomes a binding agreement. Clause 2 creates further confusion by using the words from the definition of event date. Because it is used in many places in Part 11, it is the definition of event date that should be amended, not clause 2.</p> <p>The definition of event date also does not mention arrangements with embedded generators.</p> <p>Finally, the definition of event date does not address the second scenario of switching under Schedule 11.3, when there is no arrangement with a customer but instead the gaining trader assumes responsibility for the ICP under clause 11.18(1). Such a situation may occur where a retailer assumes responsibility for an ICP in the trader default process, or an ICP that is in the registry as “ready” but the customer agreement is not finalised.</p>

Proposal	<p>The proposal is to amend the definition of event date to refer to the date that the switch occurs, without excluding arrangements with embedded generators.</p> <p>The proposed amendment adopts the drafting style used in the new clauses 1(1) and 8(1), and the amended clause 13(1), of Schedule 11.3, that will come into force on 9 October 2015 under the Electricity Industry Participation Code Amendment (ICP Switching) 2014. The proposed amendment would also be effective for the current drafting of Schedule 11.3, should it come into force before 9 October 2015.</p>
Proposed Code amendment	<p>event date, in relation to an ICP, means the date on which an arrangement between a customer and a trader for the supply of electricity at the ICP comes into effect <u>the earlier of the following dates:</u></p> <p>(a) <u>the date on which the gaining trader under clauses 1(1), 8(1) or 13(1) of Schedule 11.3 commences trading electricity at the ICP:</u></p> <p>(b) <u>the date on which the gaining trader otherwise assumes responsibility under clause 11.18(1) for the ICP.</u></p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment would have no impact on the obligations of any participant. Rather, the proposed amendment resolves an ambiguity in the drafting of the clause so as to avoid confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definition of event date in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>

principles	
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Definition of metering installation: clause 1.1(1)

Reference number(s)	082-028
Issue	It is not clear from the definition of “metering installation” that a metering installation includes metering components, which is the intended effect. Consequently, it is not clear that the definitions of “metering”, “metering installation” (under paragraph (a) of that definition), and “metering component” complement each other in the way the Authority intends under the Code.
Proposal	Amend the definition of “metering installation” to include “metering components”. The definitions of "metering" and "metering component" are not amended but are provided below for reference.
Proposed Code amendment	<p>metering means the process used to measure electricity conveyed</p> <p>metering component means a component of a metering installation including—</p> <ul style="list-style-type: none"> (a) a measuring transformer: (b) all wiring and intermediate terminals in the metering installation: (c) a control device: (d) a meter: (e) a data storage device: (f) a test facility: (g) a fuse: (h) a circuit breaker: (i) communication equipment: (j) an error compensation device <p>metering installation means—</p> <ul style="list-style-type: none"> (a) equipment, <u>including all metering components</u>, used, or intended to be used, for metering: (b) in the context of unmetered load, the calculation process used to derive the quantity of unmetered load: (c) in the context of instances of both metered electricity quantities and unmetered load, both (a) and (b)
Grounds for not consulting	The nature of the proposed amendment is technical and non-controversial because the proposed amendment clarifies an existing

	definition under the Code, and would not amend, revoke or add any obligations under the Code.
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definition in the manner proposed would reduce any potential confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative assessment has not been undertaken.

Definition of "special protection scheme": clause 1.1(1)

Reference number(s)	013-029
Issue	<p>The system operator uses special protection schemes to manage system security. Each special protection scheme is individually designed and agreed between the relevant asset owner and the system operator. Such a scheme may either reduce or increase demand or generation in order to counteract a particular condition.</p> <p>However, the definition of "special protection scheme" states that it includes reductions of demand and generation only, and does not refer to increases in demand and generation.</p> <p>Under clause 9 of Technical Code C in Schedule 8.3, each asset owner must provide a range of indications and measurements to the system operator. One of the indications required is the status of any special protection scheme.</p> <p>As noted above, some special protection schemes contemplate an increase in demand or generation. However, because the definition does not refer to such schemes, it is unclear whether the relevant indication is required in relation to those schemes. If, as a result of this ambiguity, an asset owner did not provide an indication, the system operator would be able to request the information from the asset owner under clause 9(1) of Technical Code C in Schedule 8.3 in any case. However, the situation would be less confusing if the definition of special protection scheme were amended to reflect that special protection schemes may contemplate increases as well as reductions.</p>
Proposal	Replace the word "reduction" with the word "changes" in each place it occurs, to include both reductions and increases in demand and generation.
Proposed Code amendment	<p>special protection scheme means a protection scheme that takes predetermined action, including reconfiguration of the grid, reduction <u>changes</u> of demand, or reduction <u>changes</u> of generation, to counteract a particular condition once that condition is detected.</p> <p>Special protection schemes allow a power system to be operated to a higher pre-event capacity limit while still in a secure state.</p> <p>Automatic under frequency load shedding systems and instantaneous reserves are excluded from the requirements for special protection schemes</p>

Grounds for not consulting	<p>The Authority is satisfied that the nature of the amendment is technical and non-controversial.</p> <p>This is because the proposed amendment would not have the effect of changing any participant's obligations. Rather, the proposed amendment clarifies an asset owner's obligation to provide indications to the system operator relating to the status of special protection schemes under clause 9 of Technical Code C in Schedule 8.3.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the definition in the manner proposed will reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Definition of value of expected unserved energy: clause 1.1(1) and various clauses in Part 12

Reference number(s)	015-030
Issue	<p>The definition of 'value of expected unserved energy' can cause confusion because it uses the term 'expected unserved energy', which is also defined in the Code but is not in bold in the definition.</p> <p>Several references to 'value of expected unserved energy' in Part 12 of the Code also need to be in bold. The current drafting is confusing because it is not always clear whether the definition of 'value of expected unserved energy' or the definition of 'expected unserved energy' should apply.</p>
Proposal	<p>The proposal is:</p> <ul style="list-style-type: none"> to add the word "any" immediately before the words "expected unserved energy" in the definition of "value of expected unserved energy" to bold the words "expected unserved energy" in the definition of "value of expected unserved energy" to add the word "any" immediately before the words "expected unserved energy" in clause 4(1) of Schedule 12.2 to bold the words "value of" in clauses 12.27(1)(e), 12.39(1), 12.39(6), 12.39(7), and clauses 4(2) and 4(3) of Schedule 12.2, where they appear before the bold words "expected unserved energy".
Proposed Code amendment	<p>In clause 1.1(1): value of expected unserved energy means the value of <u>any expected unserved energy</u> expected unserved energy that applies under clause 4 of Schedule 12.2</p> <p>In Schedule 12.2: 4 Value of expected unserved energy (1) The value of <u>any expected unserved energy</u> is— (a) \$20,000 per MWh; or (b) such other value as the Authority may determine. (2) The Authority may determine different values of values of expected unserved energy for different purposes and for different times. (3) If the Authority determines a value of value of expected unserved energy under this clause, the Authority must publish its determination.</p> <p>In Part 12: 12.27 Benchmark agreement</p>

	<p>(1) The benchmark agreement set out in schedule F2 of section II of part F of the rules immediately before this Code came into force, continues in force and is deemed to be the benchmark agreement that applies at the commencement of this Code, with the following amendments:</p> <p>...</p> <p>(e) the references in clause 40.2 to the value of unserved energy in schedule F4 of section III of part F of the rules must be read as references to the value of value of expected unserved energy in clause 4 of Schedule 12.2:</p> <p>....</p> <p>12.39 Customer specific value of unserved energy</p> <p>(1) In this clause, a reference to the value of unserved energy must be read as a reference to the value of value of expected unserved energy in clause 4 of Schedule 12.2.</p> <p>...</p> <p>(6) If the Authority approves the value of unserved energy proposed by Transpower or the designated transmission customer under subclause (2)(a), that value of unserved energy applies for the purposes of applying the grid reliability standards under clause 4 of Schedule 12.2 for the grid injection point or grid exit point instead of the value of value of expected unserved energy specified under clause 4 of Schedule 12.2.</p> <p>(7) If the Authority does not approve the value of unserved energy proposed by Transpower or the designated transmission customer under subclause (2)(b), the value of value of expected unserved energy under clause 4 of Schedule 12.2 applies for the purposes of applying the grid reliability standards under clauses 12.35 to 12.37 for the grid injection point or grid exit point.</p>
Grounds for not consulting	<p>The Authority is satisfied that the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment of the definition of value of expected unserved energy will not change the obligations of any participant. Similarly, the changes to the other clauses just serve to clarify which definition applies in each place.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry by clarifying the Code and thereby reducing time spent by participants interpreting the Code.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or</p>

	reliability.
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would reduce time spent by participants interpreting the Code.
Principle 3: Quantitative Assessment	It is not practicable to quantify the cost and benefits of this proposed amendment. Accordingly, a quantitative assessment has not been undertaken.

Provisions regarding block security constraints and station security constraints: Part 13

Reference number(s)	004-031
Issue	<p>Part 13 of the Code deals with two types of constraints: block security constraints and station security constraints.</p> <p>The definition of "sub-station dispatch groups" refers to the system operator notifying of station security constraints under clauses 13.61 and 13.73(1)(k). Both cross references are incorrect.</p> <p>In addition, clause 13.102 currently requires the system operator to report to the market administrator on station security constraints notified under clause 13.75(1)(g), and block security constraints notified under clause 13.61 or clause 13.75(1)(f). However, it does not currently require the system operator to report on station security constraints notified under clause 13.65. Clause 13.102 should also refer to clause 13.65.</p> <p>Clauses 13.61 and 13.75 also refer to "constraints", and it would be better if they referred to either "block security constraint" or "station security constraint", as the case may be.</p>
Proposal	<p>The definition of "sub-station dispatch groups" should refer to clause 13.65(1) not 13.61(1), and should refer to clause 13.73(1)(j) not 13.73(1)(k). The word "individual" should also be removed from the definition to make the wording of the definition of "sub-station dispatch groups" consistent with the definition of "sub-block dispatch groups", and because the word "individual" is unnecessary.</p> <p>Clauses 13.61 and 13.75 should specify whether a constraint is a block security constraint or a station security constraint.</p> <p>Clause 13.75(1)(g) should end with "; and", not a full stop.</p> <p>Clause 13.102(1)(d) should also include a reference to clause 13.65(1), which relates to station security constraints.</p>
Proposed Code amendment	<p>sub-station dispatch groups means that grouping of individual generating units or generating stations within a station dispatch group into subgroups to take account of any station security constraints notified by the system operator in accordance with clauses 13.61(1) <u>13.65(1)</u> and 13.73(1)(k) <u>13.73(1)(j)</u></p> <p>13.61 System operator to notify block security constraints (1) The system operator must notify generators of the implication</p>

	<p>of any block security constraints that apply within the block dispatch group. The notification must include—</p> <ul style="list-style-type: none"> (a) the trading periods for which the block security constraint applies; and (b) how the block security constraint divides the generating stations or generating units of a block dispatch group into sub-block dispatch groups. <p>(2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—</p> <ul style="list-style-type: none"> ... (c) notification from the system operator that the block security constraint no longer exists; or <p>13.75 Form of dispatch instruction</p> <p>(1) When issuing a dispatch instruction under clause 13.72(1)(a), the system operator must specify—</p> <ul style="list-style-type: none"> ... (f) the block security constraints that occur within a block dispatch group and how that <u>the block security constraint</u> divides the generating stations or generating units of a block dispatch group into sub-block dispatch groups as part of such a dispatch instruction; and (g) the station security constraints that occur within a station dispatch group and how that <u>the station security constraint</u> divides the generating stations or generating units of a station dispatch group into sub-station dispatch groups; <u>and</u> (h) if it is a dispatch instruction specified in clause 13.73(1)(i), the maximum reserve risk for the relevant island. ... <p>13.102 Reporting obligations of system operator</p> <p>(1) On each trading day the system operator must report to the market administrator in writing. The report must include—</p> <ul style="list-style-type: none"> ... (d) a summary of any block security constraint and station security constraint notices issued to generators in accordance with clauses 13.61(1), <u>13.65(1)</u>, and 13.75(f) and (g) during the previous trading day.
<p>Grounds for not consulting</p>	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment would have no impact on any participant's obligations. Rather, the proposed amendment</p>

	would clarify the type of constraints to which the amended clauses refer so as to avoid confusion, and corrects references to other clauses.
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the references to types of constraints and correcting the references to other clauses in the manner proposed would reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Cross referencing error: clause 8.69

Reference number(s)	091-032
Issue	<p>Clause 8.69 of the Code requires the clearing manager to determine amounts owing as a result of washups under subpart 6 of Part 14.</p> <p>Subclause (4) provides that all amounts owing under the clause are subject to the priority order of payments “set out in clause 14.47”.</p> <p>However, the cross reference to clause 14.47 should refer to clause 14.56. Clause 14.47 was the correct clause until the new Part 14 came into force on 24 March 2015. The clause that is equivalent to clause 14.47 in the new Part 14 is clause 14.56. This cross reference has been updated in other clauses (for example, clause 8.68(6)).</p> <p>The cross reference needs to be updated because otherwise clause 8.69(4) does not make sense.</p>
Proposal	The proposal is to amend the cross reference in clause 8.69(4) to refer to clause 14.56, rather than the now incorrect reference to clause 14.47.
Proposed Code amendment	<p>8.69 Clearing manager to determine wash up amounts payable and receivable</p> <p>...</p> <p>(4) All amounts owing under this clause are subject to the priority order of payments set out in clause 14.47<u>14.56</u>.</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed change to clause 8.69 will not have the effect of changing the obligations of any participant. Rather, the amendment resolves a minor cross referencing error so as to avoid confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority’s objective because it would contribute to the efficient operation of the electricity industry. Clarifying clause 8.69 in the manner proposed would avoid confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section</p>

	<p>32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Audit provision ambiguity: clause 10.17 and Schedule 10.2

Reference number(s)	017B-033
Issue	<p>It is unclear when the Authority may exercise its power to require an audit under clause 10.17 and, in particular, if that power is broader than the Authority's power to require an audit under clause 3 of Schedule 10.2.</p> <p>Additionally, clause 10.17(2) provides which auditors may conduct an audit, when all other detailed requirements for audits are contained in Schedule 10.2. Clause 10.17 also states that an audit must be undertaken by a particular type of auditor, when clause 3 of Schedule 10.2 also allows the Authority to itself conduct the audit.</p>
Proposal	<p>Amend clause 10.17 to make it clear that the Authority's power to conduct an audit is defined by clause 3 of Schedule 10.2.</p> <p>Revoke clause 10.17(2) and insert it as new clause 3A of Schedule 10.2. The new clause 3A now begins "An audit that is not undertaken by the Authority must be undertaken by an auditor...". It also specifies that auditors must be approved for the type of audit required, reflecting clause 1(7), to which the requirement refers.</p> <p>It is not proposed that clause 3 of Schedule 10.2 be amended, but it is included below for reference.</p>
Proposed Code amendment	<p>10.17 Audits</p> <p>(1) The Authority may, under clause 3 of Schedule 10.2, require a relevant participant to have an audit undertaken.</p> <p>(2) An audit must be undertaken by an auditor included in the list of approved auditors published by the Authority under clause 1(7) of Schedule 10.2.</p> <p>(3) Schedule 10.2 applies to every such audit.</p> <p>...</p> <p>Schedule 10.2</p> <p>...</p> <p>3 Authority and participant requested audits</p> <p>(1) The Authority may, in its discretion, carry out an audit, or appoint an auditor to carry out an audit, to determine whether a relevant participant has complied with this Part.</p> <p>(2) If a participant reasonably considers that a relevant participant may not have complied with this Part, the participant may request in writing to the Authority that the</p>

	<p>Authority carry out an audit of the relevant participant or that the Authority appoints an auditor to carry out an audit.</p> <p>(3) Nothing in this Schedule affects the Authority's rights under the Act or the regulations.</p> <p>...</p> <p>3A Auditor for audits</p> <p><u>An audit must be undertaken by—</u></p> <p><u>(a) the Authority; or</u></p> <p><u>(b) an auditor included in the list of approved auditors published by the Authority under clause 1(7) as being approved for the type of audit required under clause 3.</u></p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment to clause 10.17 and Schedule 10.2 would have no impact on how audits are carried out, and would not have the effect of changing the audit obligations of any participant. Rather, the proposed amendment provides clearer drafting so as to avoid potential confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the requirements in the manner proposed would reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency	<p>The proposed amendment is consistent with principle 2 in that they address problems created by the existing Code, which require an</p>

Gain or Market or Regulatory Failure	amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Metering records: clause 4(3) of Schedule 10.6

Reference number(s)	024-034
Issue	Clause 4(3) of Schedule 10.6 places an obligation on a metering equipment provider to keep metering records in relation to metering installations for which it is responsible. A metering equipment provider does not remain responsible for the metering installation if it is switched (to another metering equipment provider), or decommissioned. However, even if a metering installation is switched or decommissioned, and/or a metering component is removed from a metering installation, the metering equipment provider is still be obliged to keep the relevant metering records for at least 48 months. The existing clause does not make this clear.
Proposal	The proposal is to amend clause 4(3) of Schedule 10.6 to clarify that a metering equipment provider's obligation to keep metering records, in respect of a metering installation for which it was responsible, continues for at least 48 months even if the metering equipment provider ceases to be responsible for the metering installation.
Proposed Code amendment	<p>(3) A metering equipment provider must keep<u>retain</u> metering records relating to—</p> <p>(a) a metering component in a metering installation for which it is or was responsible, for at least 48 months after the metering component is removed from the metering installation, even if—</p> <p>(i) <u>the metering installation is subsequently decommissioned; or</u></p> <p>(ii) <u>the metering equipment provider ceases to be responsible for the metering installation; and</u></p> <p>(b) a metering installation for which it is responsible, for at least 48 months after the date on which—</p> <p>(i) <u>the metering installation is decommissioned; or</u></p> <p>(ii) <u>the metering equipment provider ceases to be responsible for the metering installation.</u></p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment to clause 4(3) of Schedule 10.6 would not have the effect of changing the obligations of any</p>

	<p>participant. Rather, the proposed amendment resolves a minor error in the drafting of the clause so as to avoid confusion about how long a metering equipment provider must keep records for, in relation to a decommissioned metering installation or a removed metering component.</p>
<p>Assessment of proposed Code amendment against section 32(1) of the Act</p>	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
<p>Assessment against Code amendment principles</p>	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
<p>Principle 1: Lawfulness.</p>	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
<p>Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure</p>	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
<p>Principle 3: Quantitative Assessment</p>	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Modification of metering installations: clause 19(3) and (3A) of Schedule 10.7

Reference number(s)	025-035
Issue	<p>Clause 19(3) of Schedule 10.7 sets out exceptions to the general rule in clause 19(1) that the certification of a metering installation is cancelled if the metering installation is modified. Subclause (3)(a) to (g) is a list of criteria, all of must be met for the certification to remain.</p> <p>One of the criteria – 19(3)(g) – provides that, for the certification of the metering installation to remain, there needs to be a control device that does not switch meter registers, and that has malfunctioned and been replaced with another certified control device that complies with subclause (3A). This is an error. The intention had been that subclause (3) should not deal with control devices. Instead, subclause (3A) should set out separate circumstances in which certification of the metering installation will not be cancelled if a control device has malfunctioned and is replaced with another certified control device.</p>
Proposal	<p>The proposal is to revoke clause 19(3)(g) of Schedule 10.7, and clause 19(3A) be amended to set out the criteria that must be met for the certification of a metering installation not to be cancelled when a control device has malfunctioned and has been replaced by another certified control device.</p> <p>A consequential change to clause 20(1)(a) of Schedule 10.7 is also required.</p>
Proposed Code amendment	<p>Clause 19(3) of Schedule 10.7 be amended as follows:</p> <p>19 Modification of metering installations</p> <p>...</p> <p>(3) Despite subclauses (1) and (2)(a), the certification of a metering installation is not cancelled if—</p> <p>...</p> <p>(f) any change of the metering installation's parameters does not affect the metrology layer; and</p> <p>(g) a control device that does not switch meter registers has malfunctioned and been replaced with another certified control device that complies with subclause (3A).</p> <p>Clause 19(3A) of Schedule 10.7 be amended as follows:</p> <p><u>(3A) Despite subclause (1) and (2)(b), the certification of a</u></p>

	<p><u>metering installation</u> is not cancelled if—</p> <p>(aa) A replacement a control device that does not switch meter registers has malfunctioned and been replaced <u>with a certified control device;</u> and complies with this subclause if—</p> <p>(a) the replacement control device has the same characteristics as the control device it replaces and—</p> <p>...</p> <p>Clause 20(1)(a) of Schedule 10.7 be amended as follows:</p> <p>20 Cancellation of certification of metering installations</p> <p>(1) The certification of a metering installation is automatically cancelled on the date on which <u>any</u> 1 of the following events takes place:</p> <p>(a) the metering installation is modified otherwise than under subclause 19(3), <u>19(3A)</u>, or 19(6):</p> <p>...</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment to clause 19(3) and (3A) will have no impact on the cancellation of metering installation certifications, and will not have the effect of changing the obligations of any participant. Rather, the amendment resolves an error in the clause so as to avoid confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the criteria in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>

Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Recording the maximum interrogation cycle: clause 26(4)-(6) of Schedule 10.7

Reference number(s)	027-036
Issue	<p>Schedule 10.7 contains requirements for certifying metering installations that incorporate meters or data storage devices. The Authority has identified two drafting issues that could cause confusion:</p> <p>(a) If a metering installation incorporates both a meter and a data storage device, an approved test house (ATH) is required to record the maximum interrogation cycle under clause 36(3) and not under clause 26(4). Clause 26(6) reflects that intent. However, clause 26(6) could usefully refer to the ATH's obligation being under clause 36. Clause 36(3) could also be clearer that it applies to a metering installation that incorporates both a meter and a data storage device.</p> <p>(b) Clauses 36 and 38 have identical headings, which is "Requirements for metering installation incorporating data storage device". Each subclause in clause 38 imposes a requirement on an ATH who is certifying a metering installation. Accordingly, the heading to clause 38 could be amended to state it is "<u>Requirements for certification of</u> metering installation incorporating data storage device".</p>
Proposal	<p>Amend clause 26(6) to include a cross reference to clause 36, and to insert the word "both" to make it clearer that it applies to a metering installation that incorporates both a meter and a data storage device.</p> <p>Amend clause 36(3) to make it clear that it also applies to a metering installation that incorporates both a meter and a data storage device.</p> <p>Amend the heading to clause 38 to include the words "certification of".</p>
Proposed Code amendment	<p>26 Requirements for metering installation incorporating meter</p> <p>(1) A metering equipment provider must ensure that each meter in a metering installation for which it is responsible is certified in accordance with this Part.</p> <p>(2) An ATH must, before it certifies a metering installation incorporating a meter, if the meter had previously been used in another metering installation, ensure that the meter has been</p>

	<p>recalibrated since it was removed from the previous metering installation, by—</p> <ul style="list-style-type: none"> (a) an approved calibration laboratory; or (b) an ATH. <p>(3) The ATH must, before it certifies a metering installation incorporating a meter, document in the metering records—</p> <ul style="list-style-type: none"> (a) any regular maintenance required for the meter in accordance with the manufacturer's recommendations; and (b) any maintenance that has been carried out on the meter (for example battery monitoring and replacement). <p>(4) An ATH must, before it certifies a metering installation incorporating a meter, record in the metering installation certification report, the maximum interrogation cycle for the metering installation.</p> <p>(5) The maximum interrogation cycle for a metering installation referred to in subclause (4) is the period of memory availability given the meter configuration.</p> <p>(6) Subclause (4) does not apply to a metering installation incorporating <u>both a meter and a data storage device (see clause 36 of Schedule 10.7).</u>—</p> <ul style="list-style-type: none"> (a) a meter; and (b) a data storage device. <p>...</p> <p>36 Requirements for metering installation incorporating data storage device</p> <p>(1) A metering equipment provider must ensure that each data storage device incorporated in a metering installation for which it is responsible, is certified in accordance with this Part.</p> <p>(2) An ATH must, before it certifies a metering installation incorporating a data storage device that had previously been used in another metering installation, ensure that the data storage device has been recalibrated since it was removed from the previous metering installation, by—</p> <ul style="list-style-type: none"> (a) an approved calibration laboratory; or (b) an approved test laboratory; or (c) an ATH. <p>(3) An ATH must, before it certifies a metering installation incorporating a data storage device (<u>including a metering installation incorporating both a meter and a data storage device</u>), record in the metering installation certification report, the maximum interrogation cycle for the data storage device.</p>
--	--

	<p>(4) The maximum interrogation cycle for a metering installation incorporating a data storage device is the shortest of the following periods:</p> <ul style="list-style-type: none"> (a) the period of inherent data loss protection for the metering installation; and (b) the period of memory availability given the data storage device configuration; and (c) the longest period in which the accumulated drift of a data storage device clock is expected to remain in compliance with the maximum time error set out in Table 1 of clause 2 of Schedule 15.2 for the category of the metering installation. <p>...</p> <p>38 Requirements for <u>certification of</u> metering installation incorporating data storage device</p> <p>...</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment does not change existing requirements and only provides greater clarity of what the requirements are. There is no change in responsibilities or obligations for any participant.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the requirements in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1:	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the</p>

Lawfulness.	requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Category 1 metering installation inspection requirements: clause 45 of Schedule 10.7

Reference number(s)	028-037
Issue	<p>Clause 45 of Schedule 10.7 relates to category 1 metering installations. It imposes obligations on the metering equipment provider (MEP) for such metering installations to ensure that an approved test house (ATH) inspects the metering installation.</p> <p>Under clause 45(1)(b), an alternative is for the MEP to ensure that a sample of the category 1 metering installations for which it is responsible are inspected by an ATH in each 12 month period. The MEP must select the metering installations to be inspected for this purpose by compiling a list in accordance with subclause (2). The MEP must then select a sample of metering installations to be inspected from the list.</p> <p>There is a minor error in the process set out in subclause (2) for compiling the list and selecting the sample. Subclause (2) provides that the MEP must compile the list by:</p> <ul style="list-style-type: none"> (a) producing a list of all the category 1 metering installations for which it is responsible (other than interim certified metering installations) (b) removing from that list any metering installations that have been certified or inspected in the last 84 months. <p>The MEP must then use the number of metering installations in the list to identify the sample size required (using a table set out in Schedule 10.1). The MEP must select a sample of metering installations (of the required size) from the list it has produced.</p> <p>The error relates to the sample size required, and is in clause 45(1)(c). Clause 45(1)(c) provides that the MEP must identify the sample size required “based on the number of metering installations identified in the list of ICP identifiers in paragraph (a)”. The cross reference to paragraph (a) is not correct. It should refer to the list of ICP identifiers under paragraphs (a) and (b).</p> <p>Otherwise, the MEP would use the larger list to identify the sample size required, before it removed the recently certified or inspected ICPs under paragraph (b). This makes paragraph (b) meaningless and results in the MEP ending up with a larger sample size than necessary.</p>

<p>Proposal</p>	<p>The proposal is to amend clause 45(2)(c) of Schedule 10.7 to correct the error. It is proposed that the reference to the “list of ICP identifiers in paragraph (a)” be changed to refer to the “list of ICP identifiers produced in accordance with paragraphs (a) and (b)”.</p> <p>This would be consistent with the approach taken in paragraph (d). The proposal also includes two minor drafting amendments:</p> <ul style="list-style-type: none"> • add bold to “identifiers” in subclause 2(b), because it is a defined term • amend subclause (2)(d) to align with the proposed new wording of subclause (2)(c). <p>Clause 45(1) would not be amended but is set out below for reference.</p>
<p>Proposed Code amendment</p>	<p>45 Category 1 metering installation inspection requirements</p> <p>(1) A metering equipment provider must ensure that—</p> <p>(a) each category 1 metering installation for which it is responsible, other than an interim certified metering installation, has been inspected by an ATH within the period set out in Table 1 of Schedule 10.1 starting from the date of the metering installation’s most recent certification; or</p> <p>(b) for each 12 month period commencing 1 January and ending 31 December, a sample, selected under subclause (2), of the category 1 metering installations for which it is responsible has been inspected by an ATH within the period set out in Table 1 of Schedule 10.1 starting from the date of the earliest certification date of a metering installation in the group.</p> <p>(2) A metering equipment provider must, for the purposes of subclause (1)(b), select a sample by—</p> <p>(a) producing a list of all ICP identifiers of each category 1 metering installation for which it is responsible, other than interim certified metering installations; and</p> <p>(b) removing from the list of ICP identifiers <u>identifiers</u>, any ICP identifier for a metering installation that has been certified or inspected in the 84 months prior to the date on which the list was produced; and</p> <p>(c) identifying the applicable required minimum sample size set out in Table 8 of Schedule 10.1, based on the number of metering installations identified in the list of ICP identifiers is <u>produced in accordance with paragraphs (a) and (b)</u>; and</p>

	<p>(d) randomly selecting a sample, of the size required under paragraph (c), from the list produced <u>in accordance with</u> under paragraphs (a) and (b).</p> <p>...</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment would not have the effect of materially changing MEPs' obligations. Rather, the proposal would resolve a cross referencing error in the drafting, which avoids confusion, and tidy up two minor drafting issues.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Ambiguity of audit provisions: clause 15.37 and Schedule 15.1

Reference number(s)	017A-038
Issue	<p>Clause 15.37 states that it applies to "An audit to be undertaken in accordance with this Code...". This suggests that the clause applies to all audits under the Code. However, Parts 3, 9, 10, 11, 12, and 13 of the Code all contain provisions relating to how different types of audits must be carried out under those parts.</p> <p>Clause 15.37, and the process to which it refers in Schedule 15.1, are only intended to apply to audits carried out under Part 15, and in some cases, Part 11 (see clause 11.11).</p> <p>It is unclear when the Authority may exercise its power to require an audit under clause 15.37(2) and, in particular, if it is broader than the power to require an audit provided in clause 12 of Schedule 15.1. It would be better if Part 15 contained only one power for the Authority to conduct an audit.</p> <p>Additionally, clause 15.37(1) specifies which auditors may conduct an audit, when all other detailed requirements for audits are contained in Schedule 15.1. Clause 15.37(1) also states that only an Authority-approved auditor can undertake an audit, when clause 12 of Schedule 15.1 also allows the Authority itself to conduct an audit.</p> <p>Clause 11.11 also refers to the audit-related clauses in Schedule 15.1. Clause 11.11 does not reflect that the Authority may appoint an auditor to conduct an audit rather than conducting the audit itself.</p>
Proposal	<p>Revoke clause 15.37(1) and insert it as a new clause 12A of Schedule 15.1, but without the reference to an audit being undertaken "in accordance with this Code". The proposed new clause 12A would begin "An audit that is not undertaken by the Authority must be undertaken by an auditor...". It would also specify that auditors must be approved for the type of audit required, reflecting clause 9(7), to which the proposed new clause would refer.</p> <p>Clause 15.37(3) is amended to refer to clause 12A of Schedule 15.1.</p> <p>Clause 12 of Schedule 15.1 is not amended, but is included below for reference.</p> <p>Clause 11.11 is amended to reflect that the Authority may appoint an auditor, to refer to clause 12A of Schedule 15.1, and to have a consistent drafting style.</p>

Proposed Code amendment	<p>15.37 Audits</p> <p>(1) <u>The Authority may, under clause 12 of Schedule 15.1, require a participant to have an audit undertaken. An audit to be undertaken in accordance with this Code must be undertaken by an auditor included in the list of approved auditors published by the Authority in accordance with clause 9(7) of Schedule 15.1.</u></p> <p>(2) The Authority may require a participant to have an audit undertaken.</p> <p>(3) Clauses 12A to 19 of Schedule 15.1 apply to every such audit.</p> <p>...</p> <p>Schedule 15.1</p> <p>...</p> <p>12 Authority and participant requested audits</p> <p>(1) If at any time the Authority reasonably considers that a participant may not have complied with a clause in this Part or Part 11, the Authority may audit the participant or appoint an auditor to carry out an audit.</p> <p>(2) If a participant reasonably considers that another participant may have not complied with a clause in this Part or Part 11, the participant may request in writing to the Authority that the Authority audit the participant or that the Authority appoints an auditor to carry out an audit.</p> <p><u>12A Auditor for audits</u></p> <p><u>An audit must be undertaken by—</u></p> <p>(a) <u>the Authority; or</u></p> <p>(b) <u>an auditor included in the list of approved auditors published by the Authority under clause 9(7) as being approved for the type of audit required under clause 12.</u></p> <p>...</p> <p>Part 11</p> <p>...</p> <p>11.11 Audits requested by Authority or participant</p> <p>(1) The Authority may carry out an audit <u>or may appoint an auditor to carry out an audit</u> in accordance with clause 12(1) of Schedule 15.1 (with all necessary amendments).</p> <p>(2) A participant may request that the Authority carry out an audit <u>or appoint an auditor to carry out an audit</u> in accordance with clause 12(2) of Schedule 15.1 (with all necessary amendments).</p> <p>(3) An audit requested by the Authority or a participant must be carried out in accordance with clauses <u>Clauses 12A13 to 19 of</u></p>
-------------------------	---

	Schedule 15.1 <u>apply to every such audit</u> (with all necessary amendments).
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment would have no impact on how audits are carried out, and would not have the effect of changing the audit obligations of any participant. Rather, the proposed amendment provides clearer drafting so as to avoid potential confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the requirements in the manner proposed would reduce confusion in this area, leading to improved operational efficiency and reduced compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendments are consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendments are consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address problems created by the existing Code, which require an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed amendments. Accordingly, a quantitative analysis has not been undertaken.

**Reference to "the market administrator" that should be to "the Authority":
clause 3(a)(ii) of Schedule 11.3**

Reference number(s)	041-039
Issue	<p>Clause 3(a)(ii) of Schedule 11.3 refers to the market administrator approving the valid switch response code, but clauses 10(a)(ii) and 15(a) refer to the Authority approving valid switch response codes.</p> <p>It is the Authority who approves the valid switch response codes.</p> <p>It is also the Authority who deals with the withdrawal of a switch request under clauses 17 and 18 of Schedule 11.3, and with the exchange of information under clauses 19 and 20.</p>
Proposal	Amend clause 3(a)(ii) of Schedule 11.3 to refer to the Authority as approving the valid switch response codes.
Proposed Code amendment	<p>3 Losing trader response to switch request</p> <p>Within 3 business days after receipt of notification from the registry in accordance with clause 22, for each ICP the losing trader must establish an expected event date and must—</p> <p>(a) provide acknowledgement of the switch request by—</p> <p>(i) providing the expected event date to the registry; and</p> <p>(ii) if relevant for that ICP, providing a valid switch response code approved by the market administrator <u>Authority</u>, to the gaining trader; or</p> <p>...</p>
Grounds for not consulting	The nature of the proposed amendment is technical and non-controversial. It clarifies an error in the existing drafting. It is non-controversial because clauses 10(a)(ii) and 15(a) already acknowledge that the Authority approves the valid switch response codes, and the role of the market administrator is currently performed by the Authority.
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote</p>

	<p>the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32 of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Registry metering records – Settlement indicator: Table 1 of Schedule 11.4

Reference number(s)	045A-040
Issue	<p>Table 1 in Schedule 11.4 contains the information that a metering equipment provider must provide to the registry for each metering installation for which it is responsible.</p> <p>Row 30 contains obligations relating to the settlement indicator identifier. It requires that the cumulative data indicator in the registry be “Y” for cumulative data channels on an AMI meter.</p> <p>The inclusion of this indicator in the registry triggers a requirement that, if a switch happens at the ICP to which the metering installation is connected, the losing trader at the ICP must provide a cumulative register read in the CS switch completion file as part of its submission information.</p> <p>This requirement was included in the Code because, if the gaining trader in the switch intends to use non-half hour metering information, the gaining trader needs a cumulative meter read to start its customer invoicing and settlement processes.</p> <p>It was intended that a gaining trader should have the option of using non-half hour metering information, half-hour metering information, or a combination of both. However, the effect of the requirement in row 30 is that if a gaining trader used half-hour AMI metering information, it would breach the Code.</p>
Proposal	<p>The proposal is to amend the Code to remove the reference to information having to be included in a trader's submission information. That would mean that a gaining trader at an ICP would have an option to use either non-half hour metering information, half-hour metering information, or a combination of both.</p> <p>It is also proposed to amend the Code to improve the drafting for clarity.</p>
Proposed Code amendment	<p>Amend column 3 of row 30 of Table 1 of Schedule 11.4 as follows:</p> <p>an identifier <u>determined as follows: that, —</u></p> <p>(a) for a if the relevant meter or data storage device with has an AMI flag of "Y", indicates that — (i) — the cumulative data channel must be identifier must be “Y” included in the trader's submission information; and; (ii) any absolute data channel must not be included in the trader's submission information;</p>

	<p>or</p> <p>(b) for any other meter or data storage device, or for a load control device, <u>the data channel identifier must be the appropriate identifier</u> indicates whether the data channel must be included in the trader's submission information, selected from a <u>the</u> list in the registry</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment to Table 1 of Schedule 11.4 is resolving a minor error in the drafting so as to avoid confusion.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the requirements in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which may inhibit competition as well as being inefficient, and requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken. There is expected to be no cost associated with the proposed amendment, as the proposed process is current practice.</p>

Revocation of redundant transitional provisions from Part 12A

Reference number(s)	094-041
Issue	<p>Part 12A includes a number of transitional provisions that are now redundant because the dates that are referred to have now passed. Those transitional provisions are included in:</p> <ul style="list-style-type: none"> (a) clause 12A.2(2), which provides that the requirement to negotiate the terms of a use-of-system agreement in good faith does not apply to an amendment to a use-of-system agreement that was in force before 1 December 2011, if the amendment is made before 1 July 2013 (b) clause 12A.3(9), which provides that the requirements relating to mediation in clause 12A.3 do not apply to an amendment to a use-of-system agreement that was in force before 1 December 2011, if the amendment is made before 1 July 2013 (c) clause 12A.7(5), which provides that clause 12A.7, which requires distributors to consult concerning changes to tariff structures, does not apply to changes made before 1 May 2012. <p>Clause 12A.13(2) provides that when publicising an EIEP under clause 12A.13(1), the Authority must specify the date on which the EIEP will come into effect, which must be no earlier than 1 November 2014. The reference to 1 November 2014 is now redundant because that date has passed.</p> <p>Clause 12A.13(4) requires the Authority to consult on each EIEP that it publicises. However, Clause 12A.13(6) provides that despite clause 12A.13(4), the Authority may publicise EIEP1, EIEP2 and EIEP3, despite the Authority having consulted on those EIEPs before clause 12A.13 came into force. EIEP1, EIEP2, and EIEP3 have been publicised by the Authority and came into effect on 1 November 2014. Accordingly, clause 12A.13(6) is now redundant.</p> <p>Clause 12A.16 relates to any EIEP with which a distributor or trader was required to comply immediately before the clause came into force, which is EIEP12. Clause 12A.16(4) provides that an agreement to record any agreement to exchange information in a way other than in accordance with EIEP12 does not need to be included in a use-of-system agreement until 1 November 2014. As that date has now passed, clause 12A.16(4) is now redundant.</p>

	<p>Clause 12A.4(8) and 12A.6(5) also include redundant transitional provisions. However it is proposed that both of those clauses be revoked as part of separate Code amendments (see items 50 and 93).</p>
Proposal	<p>The proposal is to:</p> <ul style="list-style-type: none"> (a) revoke clause 12A.2(2): (b) revoke clause 12A.3(9): (c) revoke clause 12A.7(5): (d) amend clause 12A.13(2) by deleting the words ", which must be no earlier than 1 November 2014": (e) revoke clause 12A.13(6): (f) revoke clause 12A.16(4).
Proposed Code amendment	<p>12A.2 Negotiating use-of-system agreements</p> <p>(1) A distributor and a trader must negotiate the terms of a use-of-system agreement (including any amendment to a use-of-system agreement) in good faith.</p> <p>(2) This clause does not apply to an amendment to a use-of-system agreement if—</p> <ul style="list-style-type: none"> (a) the use-of-system agreement was in force before 1 December 2011; and (b) the amendment is made before 1 July 2013. <p>12A.3 Mediation</p> <p>...</p> <p>(9) This clause does not apply to an amendment to a use-of-system agreement if—</p> <ul style="list-style-type: none"> (a) the use-of-system agreement was in force before 1 December 2011; and (b) the amendment is made before 1 July 2013. <p>...</p> <p>12A.7 Distributors must consult concerning changes to tariff structures</p> <p>...</p> <p>(5) This clause does not apply to a change to a tariff structure that is made by a distributor before 1 May 2012.</p> <p>...</p> <p>12A.13 Authority may publicise EIEPs that must be used</p> <p>(1) The Authority may publicise 1 or more EIEPs that set out standard formats that distributors and traders must use when</p>

	<p>exchanging information.</p> <p>(2) When publicising an EIEP under subclause (1), the Authority must specify the date on which the EIEP will come into effect; which must be no earlier than 1 November 2014.</p> <p>...</p> <p>(6) Despite subclause (4), the Authority may publicise the EIEPs described as EIEP1, EIEP2 and EIEP3 under this clause, despite the Authority having consulted with participants that the Authority considers likely to be affected by those EIEPs, before this clause came into force.</p> <p>12A.16 Transitional provision relating to EIEPs</p> <p>...</p> <p>(4) If a distributor and a trader agree to exchange information in a way other than in accordance with an EIEP to which this clause applies, the distributor and trader need not comply with the requirement in clause 12A.14(2)(a)(ii) to record that agreement in the use-of-system agreement between the distributor and trader until 1 November 2014.</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial. Clauses 12A.2(2), 12A.3(9), and clause 12A.7(5) are transitional provisions, which are now redundant. Clause 12A.13(6) is now redundant because the Authority has publicised EIEP1, EIEP2, and EIEP3. Similarly, the requirement in clause 12A.13(2) that any EIEPs must come into effect no earlier than 1 November 2014, and the requirement in clause 12A.16(4) relating to recording an agreement to exchange information other than in accordance with an EIEP in a use-of-system agreement by 1 November 2014, is now redundant because that date has passed.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Revoking redundant provisions as proposed would reduce confusion in this area, leading to improved operational efficiency and fewer compliance costs.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>

Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Publishing report regarding grid emergencies: clause 13.101(1)(a)

Reference number(s)	056-042
Issue	<p>Clause 13.101(1)(a) provides that if the system operator declares a grid emergency, it must, within 12 hours of the conclusion of the grid emergency, provide a written report to the Authority setting out the basis on which it decided to declare the grid emergency. The Authority must then publish this report through the information system.</p> <p>Because the system operator prepares this report and has the most significant role in managing grid emergencies under the Code, it is more practical and efficient for the system operator to publish the report.</p> <p>In addition, if the system operator were to publish this report through the information system, it would be unnecessary and inefficient for the system operator also to have to provide the report to the Authority, because the Authority could access the report from the location at which the system operator publishes it.</p>
Proposal	The proposal is to shift the obligation to publish the report on the system operator's basis for declaring a grid emergency from the Authority to the system operator. This would remove any need for the system operator to separately provide the report to the Authority, so the requirement to provide this report to the Authority could also be revoked.
Proposed Code amendment	<p>13.101 Reporting requirements in respect of grid emergencies</p> <p>(1) If the system operator declares a grid emergency,—</p> <p>(a) the system operator must, within 12 hours of the conclusion of the grid emergency, provide publish a written report to the Authority publish setting out that describes the basis on which the system operator decided decision to declare the grid emergency was made. The Authority must publish this report through the information system; and</p> <p>...</p>
Grounds for not consulting	The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section

	<p>39(3)(a) of the Act.</p> <p>The proposed amendment is technical because the system operator already has an obligation to provide the report to the Authority. The change is only to the action the system operator takes, that is, to publish the report rather than to provide it to the Authority. The proposed amendment is non-controversial because the system operator already publishes report, which participants already access through the system operator's website.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. The proposed amendment would remove an unnecessary process and its associated compliance cost.</p> <p>Accordingly, the proposed Code amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Exchanging information relating to auctions through the information system: clauses 13.114(1) and 13.118

Reference number(s)	057-043
Issue	<p>Clause 13.114(1) requires all information exchanged in relation to clauses 13.108 to 13.116 to be sent electronically using the information system. Clause 13.118 requires all information relating to auctions to be exchanged through the information system.</p> <p>Clause 13.118 effectively repeats clause 13.114(1) because all information exchanged in relation to clauses 13.108 to 13.116 relates to auctions.</p>
Proposal	To remove this duplication, clause 13.114(1) could be amended to reflect the broader wording of clause 13.118, and clause 13.118 could be revoked.
Proposed Code amendment	<p>13.114 Information to be transmitted <u>exchanged</u> through information system</p> <p>(1) All information <u>relating to auctions</u> must be exchanged in relation to clauses 13.108 to 13.116 must be sent electronically using the facility contained in <u>through</u> the information system.</p> <p>(2) If the information system is not available to send information under this clause the clearing manager must follow the backup procedures specified by the market administrator.</p> <p>(3) The backup procedures referred to in subclause (2) must be specified by the market administrator following consultation with generators and the clearing manager.</p> <p>13.118 Exchange information All information relating to auctions must be exchanged through the information system.</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment would remove a repeated obligation from the Code.</p>
Assessment of proposed Code amendment against	The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Removing duplication from the Code makes it easier for

section 32(1) of the Act	<p>participants to understand their obligations, which promotes the efficient operation of the electricity industry.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of the proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Spot price risk disclosure statements: clause 13.236A

Reference number(s)	059-044
Issue	<p>Under the Code, a disclosing participant is a person who consumes electricity that is conveyed to the person directly from the national grid, or who buys electricity from the clearing manager.</p> <p>Clause 13.236A(2) states that each disclosing participant, who will continue to be a disclosing participant in the next quarter, must prepare a spot price risk disclosure statement for that quarter.</p> <p>This means that a disclosing participant who has ceased to trade, but who has to keep purchasing from the clearing manager in relation to wash-up periods, needs to submit 'nil reports' for their non-existent purchases in future quarters.</p>
Proposal	The proposal is to add a new subclause 13.236A(4) to clarify that if a disclosing participant, in a given quarter, purchases from the clearing manager only in relation to wash-up periods, the disclosing participant does not need to prepare a spot price risk disclosure statement.
Proposed Code amendment	<p>13.236A Disclosing participants must prepare and submit spot price risk disclosure statements</p> <p>...</p> <p><u>(4) A participant is not required to comply with this clause for a quarter if it is a disclosing participant in relation to the quarter only because it is subject to a wash-up in that quarter.</u></p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment to clause 13.236A would have no impact on the submission of spot price disclosure statements, but would ensure that affected participants do not have to carry out an activity that is inefficient and serves no purpose.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed will reduce inefficiency in this area leading to reduced compliance costs.</p> <p>Accordingly, the amendment is also desirable to promote the</p>

	<p>efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	<p>The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.</p>
Principle 1: Lawfulness.	<p>The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.</p>
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	<p>The proposed amendment is consistent with principle 2 in that it would address an inefficiency created by the existing Code, which requires an amendment to resolve.</p>
Principle 3: Quantitative Assessment	<p>It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.</p>

Application for approval for a dispatch-capable load station: clause 2(b)(ii) of Schedule 13.8

Reference number(s)	061-045
Issue	<p>Clause 2(b) of Schedule 13.8 obliges the system operator to provide an application for approval for a dispatch-capable load station to the Authority and to advise a number of other parties. One of these parties is the distributor from whose network the dispatch-capable load station draws electricity.</p> <p>This is not always applicable – for example, in the case of directly connected customers.</p>
Proposal	The proposal is to state that the system operator only needs to advise the distributor if the applicant draws electricity from the distributor's network in respect of what would be the dispatch-capable load station.
Proposed Code amendment	<p>2 System operator to provide application to Authority and advise others of application</p> <p>On receipt of an application, the system operator must—</p> <ul style="list-style-type: none"> (a) provide a copy of the application to the Authority; and (b) advise the following participants that it has received the application: <ul style="list-style-type: none"> (i) the relevant grid owner; (ii) <u>each the distributor that has a from whose network from which a device that comprises or forms part of the proposed the dispatch-capable load station draws electricity:</u> <p>...</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendments to clause 2(b)(ii) of Schedule 13.8 would not have the effect of changing any participants' obligations. Rather, the proposed amendment would make a minor clarification in the clause so as to avoid confusion.</p>

Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would clarify obligations in the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Preparation of dispatchable load information by dispatchable load purchasers – clause 15.5A

Reference number(s)	064-046
Issue	<p>Clauses 15.5A and 15.5B set out the requirements for dispatchable load purchasers in relation to preparing dispatchable load information.</p> <p>Both clause 15.5A and clause 15.5B require a dispatchable load purchaser to prepare dispatchable load information using volume information. The only difference between clause 15.5A and 15.5B is that clause 15.5B applies in respect of a dispatch-capable load station's metering installation that is not at a point of connection, but that is located within premises that are directly connected to a point of connection.</p> <p>When clause 15.5B applies, the dispatchable load purchaser must adjust the raw meter data used to account for internal site losses. However, the dispatchable load purchaser must still prepare the volume information derived from the raw meter data in accordance with Schedule 15.2.</p> <p>The Authority considers that the words "unless clause 15.5B applies" in clause 15.5A(2) are confusing, because they suggest that if clause 15.5B applies, a dispatchable load purchaser is not required to use volume information prepared under Schedule 15.2. As set out above, that is not the case.</p>
Proposal	<p>The proposal is to:</p> <ul style="list-style-type: none"> (a) amend clause 15.5B(2) to make it clear that if clause 15.5B applies, dispatchable load information must be prepared using volume information prepared under Schedule 15.2; and (b) make minor drafting improvements to clauses 15.5A and 15.5B.
Proposed Code amendment	<p>15.5A Dispatchable load purchaser must prepare dispatchable load information</p> <ul style="list-style-type: none"> (1) Each dispatchable load purchaser must prepare dispatchable load information <u>using volume information prepared in accordance with Schedule 15.2.</u> (2) Unless <u>If</u> clause 15.5B applies to a dispatch-capable load station's metering installation, in preparing dispatchable

	<p>load—information, the dispatchable load purchaser responsible for the dispatch-capable load station must <u>comply with clause 15.5B in relation to the dispatch-capable load station use volume information prepared under Schedule 15.2.</u></p> <p>15.5B Deriving volume information if metering installation is within premises that are connected to a point of connection</p> <p>(1) This clause applies if a dispatch-capable load station's metering installation is not at a point of connection but is located within premises that are directly connected to a point of connection.</p> <p>(2) If this clause applies, the dispatchable load purchaser responsible for the dispatch-capable load station must prepare dispatchable load information using volume information prepared in accordance with Schedule 15.2 and derived from the raw meter data—</p> <p>...</p>
Grounds for not consulting	<p>The Authority is satisfied that the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act, on the basis that the amendment would not change dispatchable load purchasers' obligations.</p> <p>This is because clause 15.5(2) already requires dispatchable load purchasers to prepare volume information prepared in accordance with Schedule 15.2. Clause 15.5(2) applies to dispatchable load purchasers, because dispatchable load purchasers come within the definition of reconciliation participant.</p> <p>Accordingly, the proposed amendment merely corrects an ambiguity created by the drafting of clause 15.5A.</p>
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment	<p>The Authority is satisfied that the proposed amendment is consistent</p>

against Code amendment principles	with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Functions requiring certification - provision of metering information to grid owner: clause 15.38(1)(f)

Reference number(s)	095-047
Issue	<p>Clause 15.38(1) lists functions that a reconciliation participant must be certified to perform. The final item in the list is "provision of metering information to the pricing manager in accordance with subpart 4 of Part 13". The reference to "pricing manager" is incorrect. It should be a reference to the "grid owner."</p> <p>This error is the result of Code amendments in 2014. The Authority amended subpart 4 of Part 13 to provide an operational process where the grid owner receives the metering data, not the pricing manager (who does not have the facilities to do so). Clause 15.38(1)(f) should have been amended at that time, but was not.</p>
Proposal	The proposal is to amend clause 15.38(1)(f) so that it refers to the provision of metering information to the grid owner instead of to the pricing manager.
Proposed Code amendment	<p>15.38 Functions requiring certification</p> <p>(1) A reconciliation participant (except an embedded generator selling electricity directly to another reconciliation participant) must obtain and maintain certification in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:</p> <p>...</p> <p>(f) provision of metering information to the pricing manager grid owner in accordance with subpart 4 of Part 13.</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment resolves a minor error in the drafting of the clause so as to avoid confusion and ensure alignment with previous changes made to subpart 4 of Part 13.</p>
Assessment of proposed Code amendment against	The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Correcting this error in the manner proposed would reduce

section 32(1) of the Act	<p>confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Functions requiring certification: clause 15.38(1)(d), (da) & (db)

Reference number(s)	096-048
Issue	<p>The Authority has previously amended clause 15.38(1)(d), splitting it into three separate paragraphs: (d), (da), and (db).</p> <p>However, the certifications, the system for keeping track of certifications, and participants' systems all only refer to paragraph (d) and would need to be adjusted (at cost) to add in reference to the new paragraphs (da) and (db).</p>
Proposal	<p>The proposal is to return to the original paragraph numbering, to avoid the cost of updating systems. This means revoking all three paragraphs and replacing them with a single paragraph (d), containing three subparagraphs.</p>
Proposed Code amendment	<p>15.38 Functions requiring certification</p> <p>(1) A reconciliation participant (except an embedded generator selling electricity directly to another reconciliation participant) must obtain and maintain certification in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:</p> <p>...</p> <p>(d) calculation of the number of ICP days and delivery of a report under clause 15.6:</p> <p>(da) delivery of electricity supplied information under clause 15.7:</p> <p>(db) delivery of information from retailer and direct purchaser half hourly metered ICPs under clause 15.8:</p> <p><u>(d) delivery of:</u></p> <p class="list-item-l1">(i) <u>a report under clause 15.6 and the calculation of the number of ICP days detailed in the report:</u></p> <p class="list-item-l1">(ii) <u>electricity supplied information under clause 15.7:</u></p> <p class="list-item-l1">(iii) <u>information from retailer and direct purchaser half hourly metered ICPs under clause 15.8:</u></p> <p>(e) ...</p>
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendments to clause 15.38 will not</p>

	change the obligations of any participant. Rather, it would simply re-number the elements in the clause in order to avoid system changes, which will save costs for the Authority and participants.
Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Re-numbering the elements in the clause to avoid system changes will avoid unnecessary costs to the Authority and participants.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it would address a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Rounding of submission information: clause 9 of Schedule 15.3

Reference number(s)	076-049
Issue	<p>Clause 9 of Schedule 15.3 requires reconciliation participants to round submission information, which is provided to the reconciliation manager, to two decimal places. The intention is to require rounding only when there are 3 or more decimal places in the submission information.</p> <p>However, there has been some confusion about whether reconciliation participants need to add a zero onto information that has only 1 decimal place (so there are 2 decimal places). For example, whether a reconciliation participant should change 1.5 to 1.50 in the submission information it provides to the reconciliation manager.</p>
Proposal	The proposal is to amend clause 9 of Schedule 15.3 to make it clear that a reconciliation participant is not required to round submission information that has fewer than 3 decimal places. The reconciliation participant must only round the information in accordance with clause 9(a) and (b) of Schedule 15.3 if there are 3 or more decimal places.
Proposed Code amendment	<p>9 Rounding of submission information <u>If submission information aggregated by a reconciliation participant under clause 8 is specified to more than 2 decimal places, the A-reconciliation participant must round the submission information—</u></p> <ul style="list-style-type: none"> (a) to 2 decimal places; and (b) so that if the digit to the right of the second decimal place is greater than or equal to 5, the second digit is rounded up, and if the digit to the right of the second decimal place is less than 5, the second digit is unchanged.
Grounds for not consulting	<p>The Authority is satisfied that the nature of the proposed amendment is technical and non-controversial in accordance with section 39(3)(a) of the Act.</p> <p>This is because the proposed amendment to clause 9 of Schedule 15.3 will have no impact on the obligations of any participant. Rather, the proposed amendment would clarify the obligations with regards to rounding submission information so as to avoid confusion.</p>

Assessment of proposed Code amendment against section 32(1) of the Act	<p>The proposed amendment is consistent with the Authority's objective because it would contribute to the efficient operation of the electricity industry. Clarifying the obligations in the manner proposed would reduce confusion in this area, leading to improved operational efficiency.</p> <p>Accordingly, the proposed amendment is also desirable to promote the efficient operation of the electricity industry in accordance with section 32(1)(c) of the Act.</p> <p>The proposed amendment would have no effect on competition or reliability.</p>
Assessment against Code amendment principles	The Authority is satisfied that the proposed amendment is consistent with the Code amendment principles, to the extent that they are relevant.
Principle 1: Lawfulness.	The proposed amendment is consistent with the Act, as discussed above in relation to the Authority's statutory objective and the requirements set out in section 32(1) of the Act.
Principle 2: Clearly Identified Efficiency Gain or Market or Regulatory Failure	The proposed amendment is consistent with principle 2 in that it addresses a problem created by the existing Code, which requires an amendment to resolve.
Principle 3: Quantitative Assessment	It is not practicable to quantify the benefits of this proposed amendment. Accordingly, a quantitative analysis has not been undertaken.

Appendix D Master list of all proposed amendments

Universal change

All references in the Code to "lines" and "line function services" will be bolded.

Reference number: 007-024

Changes to Part 1

1.1 Interpretation

...

approved test house means a ~~meter testing and calibration~~ facility that has been approved by the **Authority** in accordance with Part 10 to do one or more of the following:

(a) **calibrate metering installations or metering components:**

(b) **certify metering installations or metering components**

Reference number: 003-022

...

~~**centralised data set**~~ means information kept by the **Authority** relating to ~~transmission and transmission alternatives~~ under clauses 12.72 to 12.75

Reference number: 049-013

...

connected asset owner means a **local network distributor** or a **direct consumer**

Reference number: 007-024

...

contract for differences, for the purposes of subpart 5 of Part 13, means a financial derivative contract—

- (a) under which 1 or both **parties** makes or may make a payment to the other **party**; and
- (b) in which the payment to be made depends on, or is derived from, the price of a specified **quantity** of **electricity** at a particular time; and
- (c) that may provide a means for the risk to 1 or both **parties** of an increase or decrease in the price of **electricity** to be reduced or eliminated; and
- (d) ~~in which that either—~~
 - (i) ~~the~~ relates to a quantity of **electricity** that ~~the contract relates to~~ equals or exceeds 0.25 MW of **electricity**; or
 - (ii) is entered into through a derivatives exchange in which **parties** trade standardised financial derivative contracts, and contracts containing the right to buy or sell standardised financial derivative contracts, with a central counterparty

Reference number: 097-001

...

de-energisation means the operation of any isolator, **circuit breaker**, or switch, or the removal of any fuse or link, so that no **electricity** can flow through a **point of connection** on a **network**, and **de-energise** and **de-energised** have corresponding meanings

Reference number: 005-026

de-energise has the meaning given to it in the definition of **energisation**

Reference number: 005-026

...

distributor has the meaning given to it by section 5 of the **Act** means as follows:

- (a) ~~except in Part 12A, and as provided in paragraphs (b) and (c), a **participant** who supplies **line function services** to another person;~~
- (b) ~~in Parts 1 (except for the definitions of **connection and operation standards**, **distribution network**, and **specified participant**), 8, 10, 11, 12, 13, 14 and 15, a **participant** who owns or operates a **local network**; and—~~
 - (i) ~~in Part 8, includes a **direct consumer**; and~~
 - (ii) ~~in Parts 10, 11, 13, 14, and 15 includes an **embedded network** owner~~
- (c) ~~for the purposes of the definitions of **connection and operation standards**, **distributed generation** and **distribution network** and Part 6, a **participant** who owns—~~
 - (i) ~~a **local network**; or~~
 - (ii) ~~an **embedded network** that is used to convey 5 GWh or more of **electricity** per annum; or~~
 - (iii) ~~a system of **lines** that—~~
 - (A) ~~is used for providing **line function services** to a person other than the owner of those **lines**; and~~
 - (B) ~~is not part of the **grid** and has no direct or indirect **connection** to the **grid**; and~~
 - (C) ~~conveys 5 GWh or more of **electricity** per annum~~

Reference number: 007-024

...

distribution has the meaning given to it by section 5 of the **Act**

Reference number: 007-024

...

EIEP means an electricity information exchange protocol that sets out standard formats for the exchange or provision of information ~~between **distributors** and **traders**.~~

Reference number: 081-023

...

electricity supplied means, for any particular period, the information relating to the quantities of **electricity** supplied by **retailers** ~~across **points of connection** to **consumers**~~, sourced directly from the **retailer's** financial records, including quantities—

- (a) that are metered or unmetered; and
- (b) supplied through normal **customer** supply and billing arrangements; and
- (c) supplied under sponsorship arrangements; and
- (d) supplied under any other arrangement; and
- (e) supplied at an **ICP** where there is no arrangement with a **consumer**

Reference number: 083-025

...

~~**embedded network** means a system of lines, substations and other works used primarily for the conveyance of **electricity** between two points (point A and point B), where—~~

- ~~(a) point A is a **point of connection** between a **local network** or another **embedded network**; and~~
- ~~(b) point B is a **point of connection** between a **consumer**, an **embedded generating station**, or both; and~~
- ~~(c) the **electricity** flow at point A is quantified by a **metering installation** in accordance with Part 10~~

Reference number: 008-002

embedded network means a system of lines, substations and other works used primarily for the conveyance of **electricity** that—

- (a) is **connected** to the **grid** only through 1 or more other **networks**; and
- (b) has 1 or more **ICP identifiers** recorded in the **registry** as being **connected** to it

Reference number: 008-002

...

energisation means the operation of an isolator, circuit breaker, or switch, or the placing of a fuse or link, so that **electricity** can flow through a **point of connection** on a **network**, and—

- ~~(a) **energise** and **energised** have corresponding meanings; and~~
- ~~(b) **de-energise** means to reverse the process of **energisation** and **de-energised** and **de-energisation** have corresponding meanings~~

Reference number: 005-026

...

event date, in relation to an **ICP**, means ~~the date on which an arrangement between a **customer** and a **trader** for the supply of **electricity** at the **ICP** comes into effect~~ the earlier of the following dates:

- (a) the date on which the gaining **trader** under clauses 1(1), 8(1) or 13(1) of Schedule 11.3 commences trading **electricity** at the **ICP**;
- (b) the date on which the gaining **trader** otherwise assumes responsibility under clause 11.18(1) for the **ICP**

Reference number: 009-027

...

~~**line function services**, for the purposes of the definition of **distributor** and in Part 12A, means the following: has the meaning given to it by section 5 of the **Act**~~

- ~~(a) the provision and maintenance of works for the conveyance of **electricity**;~~
- ~~(b) the operation of such works, including the control of voltage and assumption of responsibility for losses of **electricity**~~

Reference number: 007-024

...

lines has the meaning given to it by section 5 of the **Act**, for the purposes of the definition of **distribution network**, **distributor**, and Part 6, means works that are used or intended to be used for the conveyance of **electricity**

Reference number: 007-024

...

local network distributor means a **distributor** that owns or operates a **local network**

Reference number: 007-024

...

metering installation means—

- (a) equipment, including all **metering components**, used, or intended to be used, for **metering**;
- (b) in the context of **unmetered load**, the calculation process used to derive the quantity of **unmetered load**;
- (c) in the context of instances of both **metered electricity** quantities and **unmetered load**, both (a) and (b)

Reference number: 082-028

...

special protection scheme means a protection scheme that takes predetermined action, including reconfiguration of the **grid**, ~~reduction changes~~ of **demand**, or ~~reduction changes~~ of generation, to counteract a particular condition once that condition is detected. **Special protection schemes** allow a power system to be operated to a higher pre-event capacity limit while still in a **secure state**. **Automatic under frequency load shedding** systems and **instantaneous reserves** are excluded from the requirements for **special protection schemes**

Reference number: 013-029

...

sub-station dispatch groups means that grouping of ~~individual~~ **generating units** or **generating stations** within a **station dispatch group** into subgroups to take account of any **station security constraints** notified by the **system operator** in accordance with clauses ~~13.61(1)~~ 13.65(1) and ~~13.73(1)(k)~~ 13.73(1)(j)

Reference number: 004-031

...

use-of-system agreement means an agreement between a **distributor** and a **trader** that allows the **trader** to trade on the **distributor's local network** or embedded network

Reference number: 084-003

...

value of expected unserved energy means the value of ~~any expected unserved energy~~ **expected unserved energy** that applies under clause 4 of Schedule 12.2

Reference number: 015-030

...

1.5A Application of Code to distributors

Except in Parts 6, 9, and 12A, nothing in this Code applies to a **distributor** in respect of its **distribution** activities that are not conducted on a **network** that is—

- (a) directly **connected** to the **grid**; or
- (b) **connected** to the **grid** through 1 or more other **networks**.

Reference number: 007-024

Changes to Part 3

3.17 Market operation service provider must arrange audit of software

- (1) Unless otherwise agreed by the **Authority** in writing, each **market operation service provider** must arrange and pay for a suitably qualified independent person approved by the **Authority** to carry out—
 - (a) before any **software** is first used by the **market operation service provider** in connection with this Code (except Parts 6 and 9) and Part 2 and Subpart 1 of Part 4 of the **Act**, an **audit** of all **software** and **software specifications** to be used by the **market operation service provider**; and
 - (b) an annual **audit** of all **software** used by the **market operation service provider**, within 1 month after 1 March in each year; and
 - (c) an **audit** of any changes to the **software** or the **software specification**, before it is used by the **market operation service provider**.
- (2) A **market operation service provider** must ensure that the person carrying out an **audit** under subclause (1) provides a ~~The auditor must~~ report to the **Authority** as to—
 - (a) the performance (including likely future performance) of all of the **software** in accordance with the relevant **software specification**; and
 - (b) any other matters that the **Authority** requires.

Reference number: 002-004

Changes to Part 6

...

6.2A Application of Part to distributors in respect of embedded networks

Nothing in this Part applies to—

- (a) a **distributor** in respect of the **distributor's** ownership or operation of an **embedded network** that conveys less than 5 GWh of **electricity** per annum; or
- (b) a **distributed generator** when the **distributed generator** wishes to **connect** or has **distributed generation connected** to such an **embedded network**.

Reference number: 007-024

6.2B Application of Part to distributors in respect of systems of lines not directly or indirectly connected to the grid

Nothing in this Part applies to—

- (a) a **distributor** in respect of the **distributor's** ownership or operation of a system of **lines** that is used for providing **line function services** only to the **distributor**; or
- (b) a **distributor** in respect of the **distributor's** ownership or operation of a system of **lines**—
 - (i) that conveys less than 5 GWh of **electricity** per annum; and
 - (ii) that is not—
 - (A) directly **connected** to the **grid**; or
 - (B) **connected** to the **grid** through 1 or more other **networks**; or
- (c) a **distributed generator** when the **distributed generator** wishes to **connect** or has **distributed generation connected** to a system of **lines** described in paragraph (b).

Reference number: 007-024

...

Changes to Part 8

...

8.22 Voltage Range AOPOs

...

- (3) Each ~~distributor~~ **connected asset owner** must ensure that its **local network** is capable of being operated, and does operate, when the **grid** is operated over the range of voltages set out in subclause (1).

Reference number: 007-024

...

8.24 Load shedding obligations to support voltage

- (1) If it is not possible for a ~~distributor~~ **connected asset owner** to comply with subclause (2), the **grid owner** must, if possible, establish load shedding in block sizes and at voltage levels (and, if automatic systems are established, with relay settings) set out in the **technical codes** or otherwise as the **system operator** reasonably requires.

Reference number: 007-024

8.25 Other asset owner performance obligations and technical standards

...

- (2) Each **grid owner** and each ~~distributor~~ **connected asset owner** must use reasonable endeavours to ensure that a **generator** who meets the following criteria provides the **system operator** with written advice of the existence of its **generating unit** and the **generator's** name and address:
- (a) the **generator** is directly **connected** to the **grid owner's grid** or directly or indirectly **connected** to the **local network** (as the case may be):
 - (b) the **generator** has a **generating unit** with a rated net maximum capacity equal to or greater than 1 MW.

Reference number: 007-024

...

8.54B Ancillary service agents to provide information about interruptible load

- (1) Each **ancillary service agent** that contracts for **interruptible load** in a **network** must, within 10 **business days** of entering into the contract, give the following **participants** the information in subclause (2):
- (a) if the **interruptible load** is contracted on a **local network**, the ~~distributor~~ **connected asset owner** that operates the **local network**:
 - (b) if the **interruptible load** is contracted on an **embedded network**, the ~~distributor~~ **connected asset owner** that operates the **local network** to which the **embedded network** is **connected**:

...

- (3) If an **ancillary service agent** has given a **distributor connected asset owner** or **grid owner** information under subclause (1), the **distributor connected asset owner** or **grid owner** may require the **ancillary service agent** to provide further information about the **interruptible load** to which the contract relates.

Reference number: 007-024

...

8.54S New **distributor connected asset owners** and new **grid owners** to provide information

- (1) The purpose of this clause is to require new **distributor connected asset owner** and new **grid owners** to provide information so that their obligations under this subpart can be determined.
- (2) No later than 20 **business days** after a **distributor connected asset owner** commences taking **electricity** from the **grid**, it must give the **Authority** either—
- (a) historical records of the quantity of **electricity** consumed in the **distributor connected asset owner's network** or by the **distributor connected asset owner**; or
 - (b) if the **Authority** advises the **distributor connected asset owner** that it is not satisfied with the records given under paragraph (a), or if there are no such records, a bona fide **business plan** that permits a realistic estimate to be made of the amount of **electricity** to be consumed in the **distributor's network** or by the **distributor connected asset owner**.

Reference number: 007-024

...

8.67 Voltage support costs allocated in 3 parts – nominated peak, monthly peak and residual charges

- (1) Each **distributor connected asset owner** must pay the **allocable cost** of **voltage support** in each **zone** to the **system operator** in accordance with clause 8.68. The costs must be calculated in accordance with this clause.
- (2) Each **distributor connected asset owner** must pay a nominated peak kvar charge calculated in accordance with the following formula:

$$\text{NomCharge}_{xz} = \text{PeakRate}_z * \sum_j Q_{xjz}$$

where

NomCharge_{xz} is the total nominated peak charges for **distributor connected asset owner** x in **zone z**

Peak Rate_z is the fixed \$/kvar set annually in advance by **system operator** for **zone z**

Q_{xjz} is $\text{Nom Peak}_{\text{LINES}_{xjz}}$, which is the peak demand in kvar (in **zone z**) nominated to the **system operator** in advance of, and having effect from, 1 March each year by **distributor connected asset owner** x at its **distributor connected asset owner** kvar reference node j

\sum_j is the sum across all **distributor connected asset owner** kvar reference nodes j of **distributor connected asset owner** x in **zone z**

- (3) Each **distributor connected asset owner** must pay a monthly peak penalty charge calculated in accordance with the following formula:

$$\text{PeakPenaltyCharge}_{\text{LINE}xZ} = \text{PenaltyRate}_Z * \sum_j \text{PenaltyQuantity}_{\text{LINE}xjZ}$$

where

$\text{PeakPenaltyCharge}_{\text{LINE}xZ}$ is the total peak penalty charges for **distributor connected asset owner** x across all **distributor connected asset owner kvar reference nodes j** for **distributor connected asset owner** x in zone Z

PenaltyRate_Z is the fixed \$/kvar penalty charge for “kvar above nominated kvar” set annually in advance by the **system operator** in zone Z

\sum_j is the sum across all **distributor connected asset owner kvar reference nodes j** of **distributor connected asset owner** x in zone Z

$\text{PenaltyQuantity}_{\text{LINE}xjZ}$ is the “kvar above nominated kvar” quantity for **distributor connected asset owner** x at its **distributor connected asset owner kvar reference node j** in zone Z

- (4) For the purpose of calculating the “kvar above nominated kvar” quantity, the kvar taken by the **distributor connected asset owner**—

...

- (c) is the average of the 6 largest kvar peaks for the **distributor connected asset owner** in each month measured at the **distributor connected asset owner kvar reference node j** within the zone Z,—

and “kvar above nominated kvar” is the difference between the kvar taken by the **distributors connected asset owners** as determined in accordance with paragraphs (a) to (c) and the nominated kvar specified by the **distributor connected asset owner**.

- (5) Each **distributor connected asset owner** must pay a residual charge or receive a residual payment calculated in accordance with the following formulae:

$$\text{Residual}_{\text{ALL}Z} = \text{Vcost}_Z - \text{Nom Charge}_{\text{ALL}Z} - \text{PeakPenaltyCharge}_{\text{ALL}Z}$$

$$\text{Residual}_{\text{LINEall}Z} = \text{Residual}_{\text{ALL}Z} * (\sum_{xj} \text{NomPeak}_{\text{LINE}xjZ} / \sum_{xj} Q_{xjZ})$$

$$\text{Residual}_{\text{LINE}xZ} = \text{Residual}_{\text{LINEall}Z} * (\text{BillingPeriodOfftake}_{\text{LINE}xZ} / \text{BillingPeriodOfftake}_{\text{ALL}Z})$$

where

V_{cost_z}	is the total allocable costs for voltage support in zone z in the billing period
$Nom\ Charge_{ALLz}$	is the sum of all $Nom\ Charge_{xz}$ for zone z
$PeakPenaltyCharge_{ALLz}$	is the sum of all distributors' <u>connected asset owners'</u> $PeakPenaltyCharge_{LINExz}$ for zone z
$Residual_{ALLz}$	is the total residual to be recovered from or paid to distributors <u>connected asset owners</u> in zone z
$Residual_{LINEallz}$	is the portion of $Residual_{ALLz}$ to be recovered from or paid to distributors <u>connected asset owners</u> in zone z
$Residual_{LINExz}$	is the portion of $Residual_{LINEallz}$ to be recovered from or paid to distributors <u>connected asset owners</u> x in zone z
$BillingPeriodOfftake_{LINExz}$	is the sum of metering information for distributor <u>connected asset owner</u> x across all distributor <u>connected asset owner</u> kvar reference nodes in zone z for the billing period for all trading periods
$BillingPeriodOfftake_{ALLz}$	is the sum of metering information for all distributors <u>connected asset owners</u> across all distributor <u>connected asset owner</u> kvar reference nodes in zone z for the billing period for all trading periods
Σ_{xj}	is the sum across all distributor <u>connected asset owner</u> kvar reference nodes j for all distributors <u>connected asset owners</u> x in zone z
Σ_j	is the sum across all distributor <u>connected asset owner</u> kvar reference nodes j of distributor <u>connected asset owner</u> x in zone z
Q_{xjz}	is $Nom\ Peak_{LINEsxjz}$, which is the peak demand in kvar (in zone z) nominated to the system operator in advance of, and having effect from, 1 March each year by distributor <u>connected asset owner</u> x at its distributor <u>connected asset owner</u> kvar reference node j

- (6) For the purposes of this clause, a **distributor connected asset owner** does not include a **generator** who is supplied **electricity** for consumption at a **point of connection** with the **grid**.

Reference number: 007-024

8.67A Extended reserve costs allocated to distributors connected asset owners

If there are **allocable costs** for **extended reserve** in a **billing period**, each **distributor connected asset owner** must pay a charge for **extended reserve** for the **billing period** in accordance with the following formula:

$$\text{Extended reserve charge}_D = \left(\text{TERAC}_{\text{NI}} \times \frac{L_{\text{NI}, D}}{L_{\text{NI}, \text{TOT}}} \right) + \left(\text{TERAC}_{\text{SI}} \times \frac{L_{\text{SI}, D}}{L_{\text{SI}, \text{TOT}}} \right)$$

where

Extended reserve charge_D is the **extended reserve** charge owing by the **distributor connected asset owner** for the **billing period**

TERAC_{NI} is the sum of all payments for **extended reserve** provided in the North Island for the **billing period**

L_{NI, D} is the **distributor's connected asset owner's** total **offtake** (in MWh) at **grid exit points** in the North Island in the **billing period**

L_{NI, TOT} is the total **offtake** (in MWh) by all **distributors connected asset owners** at **grid exit points** in the North Island in the **billing period**

TERAC_{SI} is the sum of all payments for **extended reserve** provided in the South Island for the **billing period**

L_{SI, D} is the **distributor's connected asset owner's** total **offtake** (in MWh) at **grid exit points** in the South Island in the **billing period**

L_{SI, TOT} is the total **offtake** (in MWh) by all **distributors connected asset owners** at **grid exit points** in the South Island in the **billing period**.

Reference number: 007-024

8.68 Clearing manager to determine amounts owing

- (1) The **clearing manager** must determine the amount owing to the **system operator** by each **grid owner, purchaser, generator and distributor connected asset owner** for **ancillary services** under clauses 8.55 to 8.67. On behalf of the **system operator**, the **clearing manager** must collect those amounts, and any amounts advised by the **system operator** as owing to it under clauses 8.6 and 8.31(1)(a), by including the relevant amounts in the amounts advised by the **clearing manager** as owing under Part 14.

...

- (3) The **clearing manager** must determine the amount owing by each ~~distributor~~ **connected asset owner** for **extended reserve** in accordance with clause 8.67A.

Reference number: 007-024

8.69 Clearing manager to determine wash up amounts payable and receivable

- (1) The **clearing manager** must determine the following amounts owing as a result of **washups** under subpart 6 of Part 14:
- (a) the amount owing to the **system operator** by each **grid owner, purchaser, generator** and ~~distributor~~ **connected asset owner** for **ancillary services** under clauses 8.55 to 8.67:
 - (b) the amount owing to each **grid owner, purchaser, generator** and ~~distributor~~ **connected asset owner** by the **system operator** for **ancillary services** under clauses 8.55 to 8.67:
 - (c) the amount owing by each ~~distributor~~ **connected asset owner** for **extended reserve** under clause 8.67A:
 - (d) the amount owing to each **extended reserve provider** for **extended reserve** under clause 8.68.

Reference number: 007-024

- (2) On behalf of the **system operator** the **clearing manager** must collect or pay the amounts owing for **ancillary services**, and any amounts advised by the **system operator** as payable to it under clauses 8.6 and 8.31(1)(a) by including the relevant amounts advised by the **clearing manager** as owing under Part 14.
- (3) To enable the **clearing manager** to determine the amounts payable for **ancillary services**, the **system operator** must provide to the **clearing manager** the **allocable cost** for each **ancillary service** and any additional information required to carry out the recalculations under clauses 8.55 to 8.67 that is not otherwise provided by the **reconciliation manager** or the **pricing manager** under Part 13.
- (4) All amounts owing under this clause are subject to the priority order of payments set out in clause ~~14.47~~**14.56**.

Reference number: 091-032

...

Schedule 8.3 Technical Code A

...

2 General requirements

- (1) Each **asset owner** must ensure that—
- (a) its **assets** at **grid exit points** and at **grid injection points**, and, in the case of ~~distributors~~ **connected asset owners**, the **assets** of any **embedded generator connected** to it, are identified and referred to by a **system number**; and

Reference number: 007-024

...

6 Specific requirements for ~~local networks~~ connected asset owners

Each ~~distributor~~ connected asset owner must agree with the **system operator** any temporary or permanent **connection** of the ~~distributor's~~ connected asset owner's assets if those assets become simultaneously **connected** to the **grid** at more than 1 **point of connection**.

Reference number: 007-024

...

Schedule 8.3
Technical Code B

...

6 Actions to be taken by the system operator in a grid emergency

- (1) If insufficient generation and **frequency keeping** gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

...

- (b) request that a **purchaser** or a ~~distributor~~ connected asset owner reduce **demand**:

...

- (2) If insufficient transmission capacity gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

...

- (c) request that a **purchaser** or ~~distributor~~ connected asset owner reduces its **demand**:

Reference number: 007-024

...

7A Emergency load shedding

- (1) Each ~~distributor~~ connected asset owner must maintain a process for disconnection of demand for points of connection.
- (2) The process must specify the participant that will effect the disconnection of demand.
- (3) The ~~distributor~~ connected asset owner must obtain agreement for the process from the system operator and each grid owner.
- (4) Each ~~distributor~~ connected asset owner must advise the system operator of the agreed process in addition to any changes to a process previously advised.
- (5) If the system operator requires the disconnection of demand under this technical code, the system operator must instruct ~~distributors~~ connected asset owners and grid owners in accordance with the agreed process under subclause (3) to disconnect demand for the relevant point of connection.
- (6) If the system operator and a ~~distributor~~ connected asset owner or grid owner have not agreed on a process for disconnection of demand at a point of connection, the system operator must instruct grid owners to disconnect demand directly at the relevant point of connection.
- (7) To the extent practicable, the system operator must use reasonable endeavours when instructing the disconnection of demand to ensure equity between ~~distributors~~ connected

asset owners.

- (8) Each **distributor connected asset owner** or **grid owner** must act as instructed by the **system operator** operating under clause 6.

Reference number: 007-024

...

7C Obligations of extended reserve providers in security of supply situations

...

- (5) The **participants** to whom the **system operator** may issue a notice in accordance with subclause (2) are—
- (a) **distributors connected asset owners** in the North Island; and

Reference number: 007-024

...

8 Obligations of grid owners

...

- (2) A **grid owner** must take independent action as may be required by the **system operator** in accordance with clause 6(4), to disconnect demand at points of connection when any grid voltage reaches the minimum voltage limit set out in the table contained in clause 8.22(1) and is sustained at or below that level. A **grid owner** must continue to disconnect demand at points of connection while the voltage remains below that minimum voltage limit, being guided by any arrangements with **distributors connected asset owners** as advised by the **system operator**.

Reference number: 007-024

Schedule 8.3

Technical Code C, Appendix A

...

Table A3: Requirements of distributors connected asset owners

Each **distributor connected asset owner** must provide the indications and measurements shown in Table A3 in respect of **assets connected** to, or forming part of, the **grid**.

Indication or measurement	Values required	Accuracy³
Grid interface circuit breaker status	Open/ closed/ in transition/ indication error ²	N/A
Grid interface disconnector status	Open/ closed/ in transition/ indication error	N/A
Grid interface auto reclose status	Enabled/disabled/operated/locked out	N/A
Special protection scheme status	Enabled/disabled/summer/winter	N/A
Reactive plant ⁵ (eg RPC equipment, capacitor, reactor, condenser) Mvar	Import and export	±2%

Reference number: 007-024

...

Changes to Part 9

...

9.32 Auditor must provide audit report

- (1) The **retailer** must ensure that the **auditor** ~~must~~ provides the **Authority** with an **audit** report on the **retailer's** compliance with this subpart ~~that has been prepared in accordance with this clause.~~
- (2) The **audit** report must include any comments from the **retailer** on any non-compliance found by the **auditor** if the **retailer** provided the comments to the **auditor** within a time specified by the **auditor**. ~~Before the **auditor** provides the **audit** report to the **Authority**, the **auditor** must refer any non-compliance to the **retailer** for comment. The **retailer** must provide comments within a time specified by the **auditor**.~~
- ~~(3) The **auditor** must include the **retailer's** comments, if any, in the **audit** report.~~
- (4) The **audit** report must not contain ~~The **auditor** must not provide the **Authority** with a copy of~~ any of the information provided by the **retailer** to the **auditor** under clause 9.31 unless requested by the **Authority**.

Reference number: 002-027

...

Changes to Part 10

...

10.17 Audits

- (1) The **Authority** may, under clause 3 of Schedule 10.2, require a **relevant participant** to have an **audit** undertaken.
- ~~(2) An **audit** must be undertaken by an **auditor** included in the list of approved **auditors** published by the **Authority** under clause 1(7) of Schedule 10.2.~~
- (3) Schedule 10.2 applies to every such **audit**.

...

Reference number: 017B-033

10.25 Responsibility for ensuring there is metering installation for NSP that is not point of connection to grid

- (1) A **distributor** must, for each **NSP** that is not a **point of connection** to the **grid**, and for which it is recorded in the **NSP** table on the **Authority's** website as being responsible, ensure that—
 - (a) there is 1 or more **metering installations**; and
 - (b) all **electricity** conveyed is quantified in accordance with this Code;
- (2) A **distributor** must, if it proposes the creation of a new **NSP** that is not a **point of connection** to the **grid**,—
 - (a) for each **metering installation** for the **NSP**, either—
 - (i) assume responsibility for being the **metering equipment provider**; or
 - (ii) contract with a person who, in that contract, assumes responsibility for being the **metering equipment provider**; and
 - (b) no later than 20 **business days** after assuming responsibility or entering into the contract under paragraph (a), advise the **reconciliation manager** of—
 - (i) the **reconciliation participant** for the **NSP**; and
 - (ii) the **participant identifier** of the **metering equipment provider** for the **metering installation**; and
 - (c) no later than 20 **business days** after the date of **certification** of each **metering installation**, advise the **reconciliation manager participant** ~~for the **NSP**~~ of the **certification** expiry date of the **metering installation**.
- (3) In relation to an **NSP** of the type described in subclause (1), a **distributor** must, no later than 20 **business days** after a **metering installation** for such an **NSP** is **recertified**, advise the **reconciliation manager** of the following:
 - (a) the **reconciliation participant** for the **NSP**;
 - (b) the **participant identifier** of the **metering equipment provider** for the **metering installation**;
 - (c) the **certification** expiry date of the **metering installation**.

Reference number: 020-005

...

10.33 Energisation of point of connection

- (1) A **reconciliation participant** may **energise a point of connection**, or authorise a **point of connection** to be **energised**, if—
 - (a) the **reconciliation participant** is recorded in the **registry** as being responsible for the **ICP**; and
 - (b) 1 or more **certified metering installations** are in place in accordance with this Part; and
 - (c) in the case of an **ICP** that has not previously been **energised**, the owner of the **network** to which the **point of connection** is **connected** has given written approval.
- (2) A **reconciliation participant** that meets the requirements of subclause (1)(a)—
 - (a) may authorise a **metering equipment provider**, with which it has an arrangement, to request the **temporary energisation** of a **point of connection**;
 - (b) may authorise **energisation** of an **ICP** if—
 - (i) a **metering installation** is in place at the **ICP**; and
 - (ii) the **metering installation** is operational but not **certified**; and
 - (iii) the **reconciliation participant** arranges for the **certification** of the **metering installation** to be completed within 5 **business days** of the **energisation** date;
 - (c) may **energise** an **ICP** if the **point of connection** is solely for **unmetered load**.
- (3) A **reconciliation participant** must not authorise the **energisation** of a **point of connection** in any of the following circumstances:
 - (a) a **distributor** has **de-energised** the **point of connection** for safety reasons, and has not subsequently approved the **energisation**;
 - (b) the **energisation** of the **point of connection** would breach the Electricity (Safety) Regulations 2010.
- (4) No **participant** may **energise a point of connection**, or authorise the **energisation** of a **point of connection**, other than a **reconciliation participant** as described in subclauses (1) to (3).

Reference number: 022-006

...

10.34 Installation and modification of metering installations

- (1) This clause applies to a **metering equipment provider** that proposes to install or modify a each **metering installation** at a **point of connection** other than a **point of connection** to the **grid**.—
 - (a) ~~proposed to be installed at a **point of connection** other than a **point of connection** to the **grid**; or~~
 - (b) ~~at a **point of connection** other than a **point of connection** to the **grid**, which is proposed to be modified.~~
- (2) A The **metering equipment provider** must, if this clause applies, consult with and use its best endeavours to agree with the **distributor** and the **trader** for the **point of connection**, ~~before the design of the **metering installation** is finalised~~, on the matters specified in subclause (2A), before—
 - (a) finalising the design of a **metering installation** for the **point of connection**; or
 - (b) modifying the design of a **metering installation** installed at the **point of connection**.
- (2A) The matters referred to in subclause (2) are the **metering installation's**—
 - (a) required functionality; and
 - (b) terms of use; and

- (c) required interface format; and
 - (d) integration of the ripple receiver and the **meter**; and
 - (e) functionality for controllable load.
- (3) Each **participant** involved in the consultation referred to in subclause (2) must—
- (a) use its best endeavours to reach agreement; and
 - (b) act reasonably and in good faith.

Reference number: 078-007

...

10.37 Active and reactive measuring and recording requirements

- (1) A **metering equipment provider** must ensure that each **half-hour metering installation** ~~which that is a category 23 metering installation~~, or higher category of **metering installation**, **certified** after 29 August 2013 measures and separately records, in accordance with this Part,—
- (a) if the measuring and recording requirement is for consumption only—
 - (i) import **active energy**; and
 - (ii) import **reactive energy**; and
 - (iii) export **reactive energy**; or
 - (b) if the measuring and recording requirement is for consumption and generation, or generation only—
 - (i) import **active energy**; and
 - (ii) export **active energy**; and
 - (iii) import **reactive energy**; and
 - (iv) export **reactive energy**.
- (1A) A **metering equipment provider** must ensure that each **half-hour metering installation** that is a **category 2 metering installation certified** after 29 August 2013 is capable of measuring and recording—
- (a) import **active energy**; and
 - (b) export **active energy**; and
 - (c) import **reactive energy**; and
 - (d) export **reactive energy**.
- (1B) A **metering equipment provider** must ensure that each **half-hour metering installation** that is a **category 2 metering installation certified** after 29 August 2013 measures and separately records, in accordance with this Part,—
- (a) if the measuring and recording requirement is for consumption only, import **active energy**; or
 - (b) if the measuring and recording requirement is for consumption and generation, or generation only—
 - (i) import **active energy**; and
 - (ii) export **active energy**; or
- (1C) If, after consultation under clause 10.34, a **metering equipment provider** and a **distributor** or a **trader** agree, or the **Authority** determines, that a **half-hour metering installation** that is a **category 2 metering installation certified** after 29 August 2013 must measure and separately record—

- (a) import **reactive energy**, the **metering equipment provider** must ensure that the **half-hour metering installation** measures and separately records import **reactive energy**; and
 - (b) export **reactive energy**, the **metering equipment provider** must ensure that the **half-hour metering installation** measures and separately records export **reactive energy**.
- (2) Despite subclause (1)(a), (1B) and (1C)—
 - (a) each **metering installation**, for a **point of connection** to the **grid**, **certified** after 29 August 2013, must measure and separately record—
 - (i) import **active energy**; and
 - (ii) export **active energy**; and
 - (iii) import **reactive energy**; and
 - (iv) export **reactive energy**; and
 - (b) the accuracy of each local service **metering installation** for **electricity** used in and by a **grid** substation must be within the applicable accuracy tolerances set out in Table 1 of Schedule 10.1.

Reference number: 079-008

...

Schedule 10.2

...

3 Authority and participant requested audits

- (1) The **Authority** may, in its discretion, carry out an **audit**, or appoint an **auditor** to carry out an **audit**, to determine whether a **relevant participant** has complied with this Part.
- (2) If a **participant** reasonably considers that a **relevant participant** may not have complied with this Part, the **participant** may request in writing to the **Authority** that the **Authority** carry out an **audit** of the **relevant participant** or that the **Authority** appoints an **auditor** to carry out an **audit**.
- (3) Nothing in this Schedule affects the **Authority's** rights under the **Act** or the **regulations**.

...

3A Auditor for audits

An **audit** must be undertaken by—

- (a) the **Authority**; or
- (b) an **auditor** included in the list of approved **auditors published** by the **Authority** under clause 1(7) as being approved for the type of audit required under clause 3.

Reference number: 017B-033

...

Schedule 10.6

...

4 Metering equipment provider record keeping and documentation

...

- (3) A **metering equipment provider** must ~~keep~~retain **metering records** relating to—

- (a) a **metering component** in a **metering installation** for which it is or was responsible, for at least 48 months after the **metering component** is removed from the **metering installation**, even if—
 - (i) the **metering installation** is subsequently **decommissioned**; or
 - (ii) the **metering equipment provider** ceases to be responsible for the **metering installation**; and
- (b) a **metering installation** for which it is responsible, for at least 48 months after the date on which—
 - (i) the **metering installation** is **decommissioned**; or
 - (ii) the **metering equipment provider** ceases to be responsible for the **metering installation**.

Reference number: 024-034

Schedule 10.7

...

19 Modification of metering installations

...

- (3) Despite subclauses (1) and (2)(a), the **certification** of a **metering installation** is not cancelled if—
 - ...
 - (f) any change of the **metering installation's** parameters does not affect the **metrology layer**; and
 - ~~(g) a **control device** that does not switch **meter** registers has malfunctioned and been replaced with another **certified control device** that complies with subclause (3A).~~
- (3A) Despite subclause (1) and (2)(b), the **certification** of a **metering installation** is not cancelled if—
 - (aa) ~~A replacement a **control device** that does not switch **meter** registers has malfunctioned and been replaced with a **certified control device**; and complies with this subclause if—~~
 - (a) the replacement **control device** has the same characteristics as the **control device** it replaces and—

Reference number: 025-035

...

20 Cancellation of certification of metering installations

- (1) The **certification** of a **metering installation** is automatically cancelled on the date on which any 1 of the following events takes place:
 - (a) the **metering installation** is modified otherwise than under ~~subclause 19(3), 19(3A), or~~ 19(6):

Reference number: 025-035

...

26 Requirements for metering installation incorporating meter

- (1) A **metering equipment provider** must ensure that each **meter** in a **metering installation** for which it is responsible is **certified** in accordance with this Part.
- (2) An **ATH** must, unless clause 43(2) applies, before it **certifies** a **metering installation** incorporating a **meter**, if the **meter** had previously been used in another **metering installation**, ensure that the **meter** has been **recalibrated** since it was removed from the previous **metering installation**, by—
 - (a) an **approved calibration laboratory**; or
 - (b) an **ATH**.

Reference number: 087-009

- (3) The **ATH** must, before it **certifies** a **metering installation** incorporating a **meter**, document in the **metering records**—
 - (a) any regular maintenance required for the **meter** in accordance with the manufacturer's recommendations; and
 - (b) any maintenance that has been carried out on the **meter** (for example battery monitoring and replacement).
- (4) An **ATH** must, before it **certifies** a **metering installation** incorporating a **meter**, record in the **metering installation certification report**, the maximum **interrogation** cycle for the **metering installation**.
- (5) The maximum **interrogation** cycle for a **metering installation** referred to in subclause (4) is the period of memory availability given the **meter** configuration.
- (6) Subclause (4) does not apply to a **metering installation** incorporating both a **meter** and a **data storage device** (see clause 36 of Schedule 10.7).—
 - (a) ~~a **meter**~~; and
 - (b) ~~a **data storage device**~~.

Reference number: 027-036

...

36 Requirements for metering installation incorporating data storage device

- (1) A **metering equipment provider** must ensure that each **data storage device** incorporated in a **metering installation** for which it is responsible, is **certified** in accordance with this Part.
- (2) An **ATH** must, before it **certifies** a **metering installation** incorporating a **data storage device** that had previously been used in another **metering installation**, ensure that the **data storage device** has been **recalibrated** since it was removed from the previous **metering installation**, by—
 - (a) an **approved calibration laboratory**; or
 - (b) an **approved test laboratory**; or
 - (c) an **ATH**.
- (3) An **ATH** must, before it **certifies** a **metering installation** incorporating a **data storage device** (including a **metering installation** incorporating both a **meter** and a **data storage device**), record in the **metering installation certification report**, the maximum **interrogation** cycle for the **data storage device**.

- (4) The maximum **interrogation** cycle for a **metering installation** incorporating a **data storage device** is the shortest of the following periods:
- (a) the period of inherent data loss protection for the **metering installation**; and
 - (b) the period of memory availability given the **data storage device** configuration; and
 - (c) the longest period in which the accumulated drift of a **data storage device** clock is expected to remain in compliance with the maximum time error set out in Table 1 of clause 2 of Schedule 15.2 for the category of the **metering installation**.

Reference number: 027-036

...

38 Requirements for certification of metering installation incorporating data storage device

Reference number: 027-036

...

43 Metering components must be certified

- (1) An **ATH** must, before it **certifies** a **metering installation**, ensure that each **metering component** that is required to be **certified**~~certified~~ under this Part and which is in the **metering installation**—
- (a) is **certified** by an **ATH** in accordance with this Part; and
 - (b) since **certification**, has been appropriately stored and not used.
- (2) Despite subclause (1) and clause 26(2), an **ATH** may **certify** a **category 1 metering installation** that contains a **meter** which has been **certified** and subsequently installed in, and removed from, another **category 1 metering installation**, in which case, the **ATH** must (the "previous metering installation") if the **ATH**—
- (a) ~~be~~ is satisfied that external factors have not affected the accuracy of the **meter**; and
 - (b) ~~check and confirm in the certification report for the metering installation that the date on which the meter was previously installed in the other metering installation is less than 12 months before the commissioning date of the metering installation that the ATH is certifying.~~
 - (b) has confirmed that the meter was installed in the previous metering installation for no more than 12 months; and
 - (c) has confirmed that the meter was calibrated or recalibrated before being installed in the previous metering installation and after being removed from any other metering installation in which the meter was previously installed.

Reference number: 087-009

...

45 Category 1 metering installation inspection requirements

- (1) A **metering equipment provider** must ensure that—
- (a) each **category 1 metering installation** for which it is responsible, other than an **interim certified metering installation**, has been inspected by an **ATH** within the period set out in Table 1 of Schedule 10.1 starting from the date of the **metering installation's** most recent **certification**; or
 - (b) for each 12 month period commencing 1 January and ending 31 December, a sample, selected under subclause (2), of the **category 1 metering installations** for which it is responsible has been inspected by an **ATH** within the period set out in Table 1 of Schedule

10.1 starting from the date of the earliest **certification** date of a **metering installation** in the group.

- (2) A **metering equipment provider** must, for the purposes of subclause (1)(b), select a sample by—
- (a) producing a list of all **ICP identifiers** of each **category 1 metering installation** for which it is responsible, other than **interim certified metering installations**; and
 - (b) removing from the list of **ICP identifiers**, any **ICP identifier** for a **metering installation** that has been **certified** or inspected in the 84 months prior to the date on which the list was produced; and
 - (c) identifying the applicable required minimum sample size set out in Table 8 of Schedule 10.1, based on the number of **metering installations** identified in the list of **ICP identifiers** ~~is~~ produced under paragraphs (a) and (b); and
 - (d) randomly selecting a sample, of the size required under paragraph (c), from the list produced under paragraphs (a) and (b).

Reference number: 028-037

...

Changes to Part 11

...

11.11 Audits requested by Authority or participant

- (1) The **Authority** may carry out an **audit** or may appoint an auditor to carry out an **audit** in accordance with clause 12(1) of Schedule 15.1 (with all necessary amendments).
- (2) A **participant** may request that the **Authority** carry out an **audit** or appoint an auditor to carry out an **audit** in accordance with clause 12(2) of Schedule 15.1 (with all necessary amendments).
- (3) ~~An **audit** requested by the **Authority** or a **participant** must be carried out in accordance with clauses~~ Clauses 12A43 to 19 of Schedule 15.1 apply to every such **audit** (with all necessary amendments).

Reference number: 017A-038

...

11.15C Process for trader events of default

- (1) This clause applies if the **Authority** is satisfied that a **trader** has committed an **event of default** under paragraph (a) or (b) or (f) or (h) of clause 14.41.
- (2) The **Authority** and each **participant** must comply with Schedule 11.5.
- (3) This clause ceases to apply, and the **Authority** and each **participant** must cease to comply with Schedule 11.5, if the **Authority** is advised under clause 14.41(2), 14.43(3B), or 14.43(4A) that the relevant **participant** considers that the **event of default** has been remedied.

Reference number: 089-010

...

11.32B Requests for information¹⁷

...

- (2) In responding to a request, the **retailer** must comply with the procedures, and any relevant **EIEP**, publicised by the **Authority** under clause 11.32F.

...

Reference number: 081-023

...

11.32F Authority must publicise procedures for responding to requests for consumption information¹⁸

- (1) The **Authority** must, no later than 20 **business days** after this clause comes into force, **publicise** (and must keep **publicised**)—
 - (a) procedures under which a **retailer** must respond to a request from a **consumer** under clause 11.32B; and
 - (b) 1 or more **EIEPs** with which a **retailer** must comply when responding to such a request.

¹⁷ Note that clause 11.32B comes into force on 1 February 2016 – see clause 5 of the Electricity Industry Participation Code Amendment (Access to Retail Data) 2014.

¹⁸ Note that clause 11.32F comes into force on 1 February 2016 – see clause 5 of the Electricity Industry Participation Code Amendment (Access to Retail Data) 2014.

- (2) The procedures **publicised** by the **Authority** must—~~(a)~~ specify the manner in which information must be given to **consumers**; and~~;~~
- ~~(3)(b)~~ Each **EIEP** publicised by the **Authority** must specify 1 or more formats in which information must be given to **consumers**.

Reference number: 081-023

...

Schedule 11.3

...

3 Losing trader response to switch request

Within 3 **business days** after receipt of notification from the **registry** in accordance with clause 22, for each **ICP** the losing **trader** must establish an expected **event date** and must—

- (a) provide acknowledgement of the switch request by—
- (i) providing the expected **event date** to the **registry**; and
 - (ii) if relevant for that **ICP**, providing a valid switch response code approved by the ~~market administrator~~ **Authority**, to the gaining **trader**; or

...

Reference number: 041-039

...

Schedule 11.4

...

Table 1: Registry metering records

No	Registry term	Description	Fully certified metering installation	Interim certified metering installation
The following details for each metering component identified in rows 15 to 21 above				
22	metering component type	the metering component type identifier selected from the list of codes in the registry	Required <u>for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation:</u> (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power . <u>Optional for all other metering components.</u>	Required <u>for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation:</u> (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power . <u>Optional for all other</u>

			Reference number: 046-011	<u>metering components.</u> Reference number: 046-011
23	register number	a sequential number that identifies each data channel that is present in the metering component	Required for meter or data storage device or control device that returns any 1 or more of the following values as a result of an interrogation : (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power . Optional for all other metering components . Reference number: 046-011	Required for meter or data storage device or control device that returns any 1 or more of the following values as a result of an interrogation : (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power . Optional for all other metering components . Reference number: 046-011
24	number of dials	the number of dials or digits that relate to the data channel	Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation : (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power . Optional for all other metering components . Reference number: 046-011	Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation : (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power . Optional for all other metering components . Reference number: 046-011
25	register content code	an identifier for the contents of a channel or a data channel, selected from a list in the registry	Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation : (a) active energy : (b) reactive energy : (c) apparent energy : (d) apparent power .	Required for meter or data storage device that returns any 1 or more of the following values as a result of an interrogation : (a) active energy : (b) reactive energy : (c) apparent energy :

			Optional for all other metering components . Reference number: 046-011	(d) <u>apparent power</u> . Optional for all other metering components . Reference number: 046-011
26	period of availability	an identifier for the period of availability for which a control device is configured, selected from a list in the registry	Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) <u>active energy</u> : (b) <u>reactive energy</u> : (c) <u>apparent energy</u> : (d) <u>apparent power</u> . Optional for all other metering components . Reference number: 046-011	Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) <u>active energy</u> : (b) <u>reactive energy</u> : (c) <u>apparent energy</u> : (d) <u>apparent power</u> . Optional for all other metering components . Reference number: 046-011
27	unit of measurement	an identifier for the units recorded in a data channel, selected from a list in the registry	Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) <u>active energy</u> : (b) <u>reactive energy</u> : (c) <u>apparent energy</u> : (d) <u>apparent power</u> . Optional for all other metering components . Reference number: 046-011	Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) <u>active energy</u> : (b) <u>reactive energy</u> : (c) <u>apparent energy</u> : (d) <u>apparent power</u> . Optional for all other metering components . Reference number: 046-011
28	energy flow direction	an identifier for the import or export recording in the data channel, selected from a list in the registry	Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) <u>active energy</u> : (b) <u>reactive energy</u> :	Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u> (a) <u>active energy</u> :

			<p><u>(c) apparent energy:</u> <u>(d) apparent power.</u></p> <p>Optional for all other metering components.</p> <p>Reference number: 046-011</p>	<p><u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u></p> <p>Optional for all other metering components.</p> <p>Reference number: 046-011</p>
29	accumulator type	an identifier for either absolute or cumulative recording in the data channel, selected from a list in the registry	<p>Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u></p> <p><u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u></p> <p>Optional for all other metering components.</p> <p>Reference number: 046-011</p>	<p>Required for meter or data storage device <u>that returns any 1 or more of the following values as a result of an interrogation:</u></p> <p><u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u></p> <p>Optional for all other metering components.</p> <p>Reference number: 046-011</p>
30	settlement indicator	<p>an identifier <u>determined as follows: that,</u></p> <p>(a) for a if the <u>relevant meter or data storage device with has an AMI flag of "Y", indicates that—(i)—the cumulative data channel must be identifier must be "Y" included in the trader's submission information; and (ii) —any absolute data</u></p>	<p>Required for meter; <u>or or data storage device, or load control device that returns any 1 or more of the following values as a result of an interrogation:</u></p> <p><u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u></p> <p>Optional for all other metering components.</p> <p>Reference number: 046-011</p>	<p>Required for meter; <u>or or data storage device, or load control device that returns any 1 or more of the following values as a result of an interrogation:</u></p> <p><u>(a) active energy:</u> <u>(b) reactive energy:</u> <u>(c) apparent energy:</u> <u>(d) apparent power.</u></p> <p>Optional for all other metering components.</p> <p>Reference number: 046-011</p>

		<p>channel must not be included in the trader's submission information; or (b) for any other meter or data storage device, or for a load control device, <u>the data channel identifier must be the appropriate identifier</u> indicates whether the data channel must be included in the trader's submission information, selected from a the list in the registry</p> <p>Reference number: 045A-040</p>		
31	event reading	The event meter read of a meter or data storage device	Optional	Optional

...

Changes to Part 12

...

12.15 Transpower to publish information about transmission agreements and provide them on request ~~Transmission agreements to be provided to the Authority and published~~

- (1) Transpower must publish and update annually a list of all transmission agreements it has with designated transmission customers that includes, in respect of each transmission agreement contained in the list, the following information:
 - (a) the full name of the designated transmission customer that is a party to the transmission agreement; and
 - (b) the date on which the transmission agreement was executed; and
 - (c) whether the transmission agreement includes any variations from the benchmark agreement; and
 - (d) if the transmission agreement includes any variations from the benchmark agreement, a description of the variations; and
 - (e) if any schedule to the transmission agreement has been revised in accordance with clause 12.12, the date from which the revised schedule began to apply.
- ~~(1) Transpower must provide the Authority with a copy of each transmission agreement executed by Transpower as soon as reasonably practicable.~~
- ~~(1A) A person may request from Transpower a copy of a transmission agreement that Transpower has with a designated transmission customer and Transpower must provide a copy to the person as soon as practicable after receiving the request.~~
- ~~(2) The copy that is provided must be—~~
 - ~~(a) a copy of the complete transmission agreement; and~~
 - ~~(b) certified by a director or the chief executive of Transpower or the designated transmission customer, to the best of the director's or chief executive's knowledge and belief, to be a true and complete copy of the agreement.~~
- ~~(3) The Authority must publish all transmission agreements between Transpower and designated transmission customers within a reasonable time of their receipt.~~

Reference number: 047-012

...

12.27 **Benchmark agreement**

- (1) The **benchmark agreement** set out in schedule F2 of section II of part F of the **rules** immediately before this Code came into force, continues in force and is deemed to be the **benchmark agreement** that applies at the commencement of this Code, with the following amendments:
 - ...
 - (e) the references in clause 40.2 to the value of unserved energy in schedule F4 of section III of part F of the **rules** must be read as references to the ~~value of~~ **value of expected unserved energy** in clause 4 of Schedule 12.2:

Reference number: 015-030

...

12.39 Customer specific value of unserved energy

- (1) In this clause, a reference to the value of unserved energy must be read as a reference to the ~~value of~~ **value of expected unserved energy** in clause 4 of Schedule 12.2.

...

- (6) If the **Authority** approves the value of unserved energy proposed by **Transpower** or the **designated transmission customer** under subclause (2)(a), that value of unserved energy applies for the purposes of applying the **grid reliability standards** under clause 4 of Schedule 12.2 for the **grid injection point** or **grid exit point** instead of the ~~value of~~ **value of expected unserved energy** specified under clause 4 of Schedule 12.2.
- (7) If the **Authority** does not approve the value of unserved energy proposed by **Transpower** or the **designated transmission customer** under subclause (2)(b), the ~~value of~~ **value of expected unserved energy** under clause 4 of Schedule 12.2 applies for the purposes of applying the **grid reliability standards** under clauses 12.35 to 12.37 for the **grid injection point** or **grid exit point**.

Reference number: 015-030

...

12.52 Contents of this subpart

This subpart relates to—

- (a) **grid reliability standards**; and
- (b) **investment contracts**; and
- ~~(c) **centralised data set**; and~~
- (d) grid reliability reporting.

Reference number: 049-013

...

Centralised data set

Reference number: 049-013

~~12.72 Authority to establish and maintain centralised data set~~

- ~~(1) The **Authority** must establish and maintain a **centralised data set**.~~
- ~~(2) The **centralised data set** at the commencement of this Code is the **centralised data set published** by the Electricity Commission under rule 11 of section II of part F of the **rules** immediately before this Code came into force.~~

Reference number: 049-013

~~12.73 Purpose of centralised data set~~

~~The purpose of the **centralised data set** is to support efficient planning processes by ensuring collection and ongoing maintenance by the **Authority** of the factual and historical information required to make efficient and effective decisions on transmission and **transmission alternatives**.~~

Reference number: 049-013

12.74 ~~Contents of centralised data set~~

A ~~centralised data set~~ should include—

- (a) ~~provisions for updating and maintenance of data; and~~
- (b) ~~information on network capabilities, performance and constraints.~~

Reference number: 049-013

12.75 ~~Public access to centralised data set~~

Subject to clause 12.54(4), the ~~Authority~~ must ~~publish the centralised data set.~~

Reference number: 049-013

...

12.97 Audit of transmission prices

- (1) The **Authority** may appoint an **auditor** to confirm whether **Transpower's** transmission prices have been calculated in accordance with the **transmission pricing methodology**.
- (2) **Transpower** must ensure that the~~The~~ **auditor's** report ~~must consider~~ includes the auditor's view on whether the application of the **transmission pricing methodology** by **Transpower** contains errors or inconsistencies that may have a material impact on the prices of any individual **designated transmission customers**, or **designated transmission customers** in general.
- (3) **Transpower** must provide the **auditor** with all relevant information required by the **auditor** to complete its review.

Reference number: 002-004

12.98 Transpower may respond to auditor's report

Transpower must ensure that the auditor's report includes any comments that Transpower provided to the auditor ~~be provided with the opportunity to respond in writing to the auditor's report~~ within 15 **business days** of **Transpower** receiving the a draft of the report, ~~before the finalization of the audit report.~~

Reference number: 002-004

12.99 Final auditor report to the Authority

- (1) **Transpower** must ensure that, within ~~Within~~ 10 **business days** after the auditor receives receipt ~~of Transpower's response under clause 12.98, the auditor must provides a report to the Authority~~ certifying that either—
 - (a) **Transpower** had applied correctly the approved **transmission pricing methodology**; or
 - (b) material errors remained in the application by **Transpower** of the **transmission pricing methodology**.
- (2) Within 5 **business days** of receiving the report, the **Authority** must **publish** the **auditor's** report.

Reference number: 002-004

...

12.116 Information on capacities of individual interconnection assets

...

- (2) The information required under subclause (1)—
 - (a) must be consistent with the **manufacturer's specification** for the **asset** or with the most recent **asset capability statement** provided by **Transpower** under clause 2(5) of

Technical Code A of Schedule 8.3, if this differs from the **manufacturer's specification**; and

- (b) must be provided in a form that allows the **branch** to which each **asset** belongs to be easily identified; and
- (c) ~~must be published either in the centralised data set maintained under clause 12.72 or some other form~~, if the **Authority** so determines, must be published by. ~~If the Authority determines that the information must be published in different form, Transpower must publish the information in that~~ in the form determined by the Authority as soon as reasonably possible practicable after the **Authority** has determined the ~~different~~ form.

Reference number: 049-013

...

Schedule 12.1

1 Categories of designated transmission customers required to enter into transmission agreements with Transpower

- (1) The categories of **designated transmission customers** required to enter into **transmission agreements** with **Transpower** are—
 - (a) **direct consumers** that have a **point of connection** to the **grid**; and
 - (b) **local network distributors**; and
 - (c) **generators** that are directly **connected** to the **grid**.

Reference number: 007-024

...

Schedule 12.2

...

4 Value of expected unserved energy

- (1) The value of any expected unserved energy is—
 - (a) \$20,000 per MWh; or
 - (b) such other value as the **Authority** may determine.
- (2) The **Authority** may determine different ~~values of~~ values of **expected unserved energy** for different purposes and for different times.
- (3) If the **Authority** determines a ~~value of~~ value of **expected unserved energy** under this clause, the **Authority** must **publish** its determination.

Reference number: 015-030

...

Changes to Part 12A

12A.1 Contents of this Part

This Part—

- (a) specifies requirements that must be complied with in negotiating **use-of-system agreements**; and
- (b) specifies requirements that must be complied with if prudential requirements are included in **use-of-system agreements**; and
- ~~(c) requires that an indemnity be included in every **use-of-system agreement** unless agreed otherwise; and~~

Reference number: 093-014

...

12A.2 Negotiating use-of-system agreements

- (1) A **distributor** and a **trader** must negotiate the terms of a **use-of-system agreement** (including any amendment to a **use-of-system agreement**) in good faith.
- ~~(2) This clause does not apply to an amendment to a **use-of-system agreement** if—~~
 - ~~(a) the **use-of-system agreement** was in force before 1 December 2011; and~~
 - ~~(b) the amendment is made before 1 July 2013.~~

Reference number: 094-041

...

12A.3 Mediation

...

- ~~(9) This clause does not apply to an amendment to a **use-of-system agreement** if—~~
 - ~~(a) the **use-of-system agreement** was in force before 1 December 2011; and~~
 - ~~(b) the amendment is made before 1 July 2013.~~

Reference number: 094-041

12A.4 Prudential requirements

- ~~(1) This clause and e~~Clauses 12A.4A to 12A.5A apply in relation to a **use-of-system agreement** if—
- (a) the **distributor** party to the **use-of-system agreement** has 1 or more **consumers connected** to its **network** to whom the **distributor** does not send accounts for **line function services** directly; and
- (b) the **distributor's** charges for **line function services** are collected from **consumers** or paid by the **trader** party to the **use-of-system agreement** in accordance with the **use-of-system agreement**; and
- (c) the **distributor** requires that the **use-of-system agreement** provides that the **trader**—
 - (i) must comply with prudential requirements; or
 - (ii) must comply with prudential requirements if required to do so by the **distributor**.

Reference number: 050-015

12A.4A Election of prudential requirements

- (1)2) Subject to subclause 12A.5A(7), if a **use-of-system agreement** provides that the **trader** party to the **use-of-system agreement** must comply with prudential requirements, including if required to do so by the **distributor**, the **use-of-system agreement** must provide the **use-of-system agreement** must provide that the **trader** may elect to comply with the prudential requirements under the **use-of-system agreement** in either of the following ways:
- (a) the **trader** must maintain an acceptable credit rating in accordance with subclause (3)4); or
 - (b) the **trader** must provide and maintain acceptable security by, at the **trader's** election,—
 - (i) providing the **distributor** with a cash deposit; or
 - (ii) arranging for a third party with an acceptable credit rating to provide that security in a form acceptable to the **distributor**; or
 - (iii) providing a combination of the securities described in subparagraphs (i) and (ii).
- (2)3) The **use-of-system agreement** must provide that the **trader**—
- (a) ~~must make the elections referred to in subclause (2) before the commencement of the use-of-system agreement; and~~
 - (b) ~~may change an its election at any time.~~
- (3)4) For the purposes of this clause, ~~an acceptable credit rating means that the trader or the third party has an acceptable credit rating if it (as the case may be) —~~
- (a) carries a long term credit rating of at least—
 - (i) BBB- (Standard & Poors Rating Group); or
 - (ii) a rating that is equivalent to the rating specified in subparagraph (i) from a rating agency that is an approved rating agency for the purposes of Part 5D of the Reserve Bank of New Zealand Act 1989; and
 - (b) ~~if the trader or the third party (as the case may be) carries a credit rating at the minimum level required by paragraph (a), is not subject to negative credit watch or any similar arrangement by the agency that gave it the credit rating.~~
- (4)5) Subject to clause 12A.5, the value of the acceptable security described in subclause (2)(1)(b) must be the **distributor's** reasonable estimate of the **line function services** charges that the **trader** will be required to pay to the **distributor** in respect of any period of not more than 2 weeks.
- (5)6) A **use-of-system agreement** must specify that, if the **trader** elects to provide acceptable security as described in subclause (2)(1)(b), the **distributor** must—
- (a) hold any security provided by the **trader** ~~trader~~ in the form of a cash deposit in a trust account in the name of the **trader** ~~trader~~ at an interest rate that is the best on-call rate reasonably available at the time the **trader** provides the cash deposit; and
 - (b) pay interest earned in respect of the cash deposit to the **trader** ~~trader~~ on a quarterly basis, net of account fees and any amounts that are required to be withheld by law.
- (7) ~~Despite subclauses (2) to (6), a distributor and a trader may agree prudential requirements that are less onerous on the trader than the requirements described in subclauses (2) to (6).~~
- (8) ~~This clause and clause 12A.5 do not apply, until 1 May 2012, to a use-of-system agreement that was in force before 1 December 2011.~~

12A.5 Requirements if distributors require additional security

- (1) A **distributor** may require that its **use-of-system agreement** provides 1 or both of the following:
 - (a) that if the **trader** elects to provide acceptable security as specified in clause 12A.4A(2)(b), the **trader** must provide acceptable security that is additional to the amount provided for in clause 12A.4A(4)5);
 - (b) that the **distributor** may, during the term of the **use-of-system agreement**, require the **trader** ~~trader~~ to provide such additional security.
- (2) If a **use-of-system agreement** has a provision provided for in subclause (1), the **distributor** must ensure that the total value of additional security specified in the **use-of-system agreement** must be such that the total value of all security required to be provided by the **trader** must not be more than the **distributor's** reasonable estimate of the **line function services** charges that the **trader** will be required to pay to the **distributor** in respect of any 2 month period.
- (3) If a **use-of-system agreement** has a provision provided for in subclause (1), the **distributor** must ensure that the **use-of-system agreement** provides the following:
 - (a) if any additional security provided by the **trader** is in the form of a cash deposit, the **distributor** must pay a charge to the **trader** for each day that the **distributor** holds the additional security at a per annum rate equal to the sum of the bank bill yield rate for that day plus 15% on the amount of additional security held on that day;
 - (b) if any additional security provided by the **trader** is in the form of security from a third party, the **distributor** must pay a charge to the **trader** for each day that the **distributor** holds the additional security at a per annum rate of 3% on the amount of additional security held on that day;
 - (c) any money required to be paid by the **distributor** to the **trader** ~~in accordance with as specified in paragraph (a) or paragraph (b)~~ must be paid by the **distributor** to the **trader** on a quarterly basis.
- (4) For the purposes of this clause, the bank bill yield rate is—
 - (a) the daily bank bill yield rate (rounded upwards to 2 decimal places) published on the wholesale interest rates page of the website of the Reserve Bank of New Zealand (or its successor or equivalent page) on that day as being the daily bank bill yield for bank bills having a tenor of 90 days; or
 - (b) for any day for which such a rate is not available, the bank bill yield rate is deemed to be the bank bill yield rate determined in accordance with paragraph (a) on the last day that such a rate was available.

Reference number: 050-015

12A.5A Agreement to less onerous terms

Despite clause 12A.4A, a **distributor** and a **trader** may agree prudential requirements that are less onerous on the **trader** than the requirements described in clause 12A.4 to 12A.5.

Reference number: 050-015

12A.6 Distributor indemnity

- ~~(1) Every **use-of-system agreement** must include the clause specified in Schedule 12A.1.~~
- ~~(2) Every **use-of-system agreement** that does not include the clause specified in Schedule 12A.1 is deemed to include that clause.~~
- ~~(3) A **distributor** may include in a **use-of-system agreement** an indemnity that is more favourable to the **trader** than the indemnity specified in Schedule 12A.1, and, in that case, subclauses (1) and (2) do not apply to the **use-of-system agreement**.~~
- ~~(4) This clause does not apply to a **use-of-system agreement** if the **distributor** and the **trader** who are parties to the **use-of-system agreement** agree to omit the clause specified in Schedule 12A.1 from the **use-of-system agreement**.~~
- ~~(5) Subclause (1) does not apply, until 1 May 2012, to a **use-of-system agreement** that was in force before 1 December 2011.~~

Reference number: 093-014

...

12A.7 Distributors must consult concerning changes to tariff structures

...

- ~~(5) This clause does not apply to a change to a tariff structure that is made by a **distributor** before 1 May 2012.~~

Reference number: 094-041

...

12A.13 Authority may publicise EIEPs that must be used

- (1) The **Authority** may **publicise** 1 or more **EIEPs** that set out standard formats that **distributors** and **traders** must use when exchanging information.
- (2) When **publicising** an **EIEP** under subclause (1), the **Authority** must specify the date on which the **EIEP** will come into effect, ~~which must be no earlier than 1 November 2014.~~

...

- ~~(6) Despite subclause (4), the **Authority** may **publicise** the **EIEPs** described as EIEP1, EIEP2 and EIEP3 under this clause, despite the **Authority** having consulted with **participants** that the **Authority** considers likely to be affected by those **EIEPs**, before this clause came into force.~~

Reference number: 094-041

...

12A.14 Distributors and traders must comply with EIEPs

- (1) If the **Authority** ~~has publicised~~ an **EIEP** under clause 12A.13, the **distributor** and the **trader** must, when exchanging information to which the **EIEP** relates applies, comply with the **EIEP** from the date on which the **EIEP** comes into effect.
- ~~(2) Subclause (1) does not apply —~~
 - ~~(a) if —~~
 - ~~(i) the **distributor** and **trader** agree to exchange the information in any other way; and~~

- (ii) ~~that agreement is recorded in the use-of-system agreement between the distributor and the trader; or~~
- (b) ~~to an EIEP publicised under clause 12A.15.~~
- (3) However, a distributor and a trader may, after an EIEP has been publicised, agree to exchange information other than in accordance with the EIEP, by recording the agreement in each use-of-system agreement between the distributor and trader.
- (4) An agreement to exchange information other than in accordance with an EIEP is not effective in relieving a distributor and a trader of the obligation to comply with subclause (1), unless the agreement comes into effect on or after the date on which the relevant EIEP comes into effect.
- (5) An agreement under subclause (3) is not affected by the Authority publicising an amendment to the EIEP.
- (6) Subclause (1) does not apply to an EIEP publicised under clause 12A.15.

Reference number: 051-016

...

12A.16 Transitional provision relating to EIEPs

...

- (4) ~~If a distributor and a trader agree to exchange information in a way other than in accordance with an EIEP to which this clause applies, the distributor and trader need not comply with the requirement in clause 12A.14(2)(a)(ii) to record that agreement in the use-of-system agreement between the distributor and trader until 1 November 2014.~~

Reference number: 094-041

...

Schedule 12A.1

Distributor indemnity in use-of-system agreements

Every ~~use-of-system agreement~~ is deemed to include the following clause:

Distributor indemnity

- (1) ~~If~~
 - (a) ~~there has been a failure of the acceptable quality guarantee in section 6 of the Consumer Guarantees Act 1993 in the supply of electricity to a Consumer by the Retailer (a "failure"); and~~
 - (b) ~~the failure was wholly or partially the result of an event or condition associated with the Distributor's Network; and~~
 - (c) ~~the failure was not a result of the Distributor complying with a rule or order with which it was legally obliged to comply; and~~
 - (d) ~~the Consumer obtains a remedy under Part 2 of the Consumer Guarantees Act 1993 in relation to the failure against the Retailer; and~~
 - (e) ~~that remedy is a cost to the Retailer (a "remedy cost"), the Distributor indemnifies the Retailer for the remedy cost.~~
- (2) ~~The amount of the Distributor's liability under this indemnity is limited to the proportion of the remedy cost that is attributable to the event or condition associated with the Distributor's Network.~~

- (3) ~~However,~~
- ~~(a) if the Distributor pays compensation to a Consumer ("payment A") in respect of a service provided directly by the Distributor to the Consumer; and~~
 - ~~(b) the Retailer incurs remedy costs in relation to the Consumer for a failure of acceptable quality that arose from the same event or circumstance that led to the payment of payment A; then~~
 - ~~(c) the amount that the Retailer would otherwise recover from the Distributor in respect of that Consumer must be reduced by the amount of payment A.~~
- (4) ~~If a Consumer makes a claim against the Retailer that the Retailer wishes to be indemnified for under this indemnity (a "claim"), the Retailer will:~~
- ~~(a) as soon as reasonably practicable, give written notice of the claim to the Distributor specifying the nature of the claim in reasonable detail; and~~
 - ~~(b) consult with and keep the Distributor informed in relation to the claim.~~

Reference number: 093-014

Changes to Part 13

...

13.61 System operator to notify block security constraints

- (1) The **system operator** must notify **generators** of the implication of any **block security constraints** that apply within the **block dispatch group**. The notification must include—
 - (a) the **trading periods** for which the **block security constraint** applies; and
 - (b) how the **block security constraint** divides the **generating stations** or **generating units** of a **block dispatch group** into **sub-block dispatch groups**.
- (2) If a notice has been sent in accordance with subclause (1), the notice remains valid until the earliest of—
 - (c) notification from the **system operator** that the **block security constraint** no longer exists; or

...

Reference number: 004-031

...

13.75 Form of dispatch instruction

- (1) When issuing a **dispatch instruction** under clause 13.72(1)(a), the **system operator** must specify—
 - (f) the **block security constraints** that occur within a **block dispatch group** and how ~~that the~~ **block security constraint** divides the **generating stations** or **generating units** of a **block dispatch group** into **sub-block dispatch groups** as part of such a **dispatch instruction**; and
 - (g) the **station security constraints** that occur within a **station dispatch group** and how ~~that the~~ **station security constraint** divides the **generating stations** or **generating units** of a **station dispatch group** into **sub-station dispatch groups**; and
 - (h) if it is a **dispatch instruction** specified in clause 13.73(1)(i), the maximum reserve risk for the relevant island.

Reference number: 004-031

...

13.101 Reporting requirements in respect of grid emergencies

- (1) If the **system operator** declares a **grid emergency**,—
 - (a) the **system operator** must, within 12 hours of the conclusion of the **grid emergency**, ~~provide~~ **publish** a written report to the ~~Authority setting out that describes~~ the basis on which the **system operator** ~~decided~~ decision to declare the **grid emergency** ~~was made~~. The **Authority** must ~~publish~~ this report through the **information system**; and

Reference number: 056-042

...

13.102 Reporting obligations of system operator

- (1) On each **trading day** the **system operator** must report to the **market administrator** in writing. The report must include—

...

- (d) a summary of any **block security constraint** and **station security constraint** notices issued to **generators** in accordance with clauses 13.61(1), 13.65(1), and 13.75(f) and (g) during the previous **trading day**.

Reference number: 004-031

...

13.114 Information to be ~~transmitted~~ exchanged through information system

- (1) All information relating to **auctions** must be exchanged in relation to clauses 13.108 to 13.116 ~~must be sent electronically using the facility contained in~~ through the **information system**.
- (2) If the **information system** is not available to send information under this clause the **clearing manager** must follow the backup procedures specified by the **market administrator**.
- (3) The backup procedures referred to in subclause (2) must be specified by the **market administrator** following consultation with **generators** and the **clearing manager**.

Reference number: 057-043

...

13.118 Exchange information

~~All information relating to **auctions** must be exchanged through the **information system**.~~

Reference number: 057-043

...

13.231 Audit of information

- (1) The **Authority** may, in its discretion, carry out an **audit** as to whether a **participant** has complied with this subpart.
- (2) If the **Authority** decides under subclause (1) that a **participant** should be subject to an **audit**, the **Authority** must first require the **participant** to nominate an appropriate **auditor**. The **participant** must provide that nomination within a reasonable timeframe. The **Authority** must appoint the **auditor** nominated by the **participant**. If the **participant** fails to nominate an appropriate **auditor** within a reasonable timeframe, the **Authority** may appoint an **auditor** of its own choice.
- (3) A **participant** subject to an **audit** under this clause must, on request from the **auditor**, provide the **auditor** with a copy of every **risk management contract** that it has entered into in the previous 12 months or within such other period specified by the **auditor**. The **participant** must provide this **audit** information no later than 20 **business days** after receiving a request from the **auditor** for the information.
- (4) ~~The **participant** must ensure that the **auditor** provides the **Authority** with must produce an **audit** report on the **participant's** compliance with this subpart that has been prepared in accordance with subclauses (5) and (6). Before the **audit** report is submitted to the **Authority**, any non-compliance must be referred back to the **participant** for comment. The comments of the **participant** must be included in the **audit** report.~~

- (4A) The **audit** report must include any comments from the **participant** on any non-compliance found by the **auditor** if the **participant** provided comments to the **auditor** within a time specified by the **auditor**.
- (5) The **audit** report must not contain ~~The **auditor** must not provide the **Authority** with a copy of any **risk management contract** that the **participant** has provided to the **auditor** in accordance with subclause (3), unless the **Authority** has specifically requested that the **auditor** do so.~~

Reference number: 002-004

...

13.236A Disclosing participants must prepare and submit spot price risk disclosure statements

...

- (4) A **participant** is not required to comply with this clause for a quarter if it is a **disclosing participant** in relation to the quarter only because it is subject to a **wash-up** in that quarter.

Reference number: 059-044

...

Schedule 13.8

...

2 System operator to provide application to Authority and advise others of application

On receipt of an application, the **system operator** must—

- (a) provide a copy of the application to the **Authority**; and
- (b) advise the following **participants** that it has received the application:
 - (i) the relevant **grid owner**;
 - (ii) each the **distributor** that has a from whose **network** from which a device that comprises or forms part of the proposed the **dispatch-capable load station** draws electricity:

Reference number: 061-045

...

Changes to Part 14

...

14.41 Definition of an event of default

(1) Each of the following events constitutes an **event of default**:

...

- (h) termination of a **trader's use-of-system agreement** with a **distributor** because of a **serious financial breach** if—
 - (i) the **trader** continues to have a **customer** or **customers** on the **distributor's local network**; and
 - (ii) there are no unresolved disputes between the **trader** and the **distributor** in relation to the termination; and
 - (iii) the **distributor** has not been able to remedy the situation in a reasonable time; and
 - (iv) the **distributor** gives notice to the **Authority** that this subclause ~~clause~~ applies.

(2) If a **distributor**, having given notice under subclause (1)(h)(iv), considers that an **event of default** no longer exists, the **distributor** must advise the **Authority** that it considers that the **event of default** has been remedied.

Reference number: 089-010

14.42 Clearing manager to advise Authority of anticipated event of default

(1) If the **clearing manager** believes that an **event of default** is likely to occur, the **clearing manager** must advise the **Authority** so that the **Authority** can consider an appropriate course of action.

(2) If the **clearing manager**, having advised the **Authority** under subclause (1), no longer believes that an **event of default** is likely to occur, the **clearing manager** must advise the **Authority** that it no longer believes that the **event of default** is likely to occur.

Reference number: 089-010

14.43 Procedure upon event of default

(1) If an **event of default** occurs in relation to a **participant**, the **participant** must immediately advise the **clearing manager** and the **Authority** of the **event of default**.

(2) Despite subclause (1), a **participant** is not required to advise the **clearing manager** or the **Authority** if the **participant** would breach section 36 of the Corporations (Investigation and Management) Act 1989 by advising the **clearing manager** or the **Authority**.

(3) If subclause (2) applies, the **participant** must seek the consent of the Registrar of Companies or the Financial Markets Authority (as applicable) to disclose the matter to the **clearing manager** and the **Authority**.

(3A) If a **participant**, having advised of an **event of default** under subclause (1), considers that the **event of default** has been remedied, the **participant** must advise the **clearing manager** that it considers that the **event of default** has been remedied.

(3B) If the **clearing manager** has been advised under subclause (3A) that the **participant** considers that an **event of default** has been remedied, the **clearing manager** must—

- (a) decide whether it agrees that the **event of default** has been remedied; and

- (b) if it agrees, advise the **Authority** that it considers that the **event of default** has been remedied.
- (4) If the **clearing manager** becomes aware that an **event of default** under paragraphs (a) to (g) of clause 14.41 has occurred and is continuing in relation to a **participant**, the **clearing manager** must—
 - (a) advise the **Authority** that the **event of default** has occurred; and
 - (b) if the **participant** has not advised the **clearing manager** of the **event of default**, advise the defaulting **participant** that the **event of default** has occurred.
- (4A) If the **clearing manager**, having advised of an **event of default** under subclause (4), considers that the **event of default** has been remedied, the **clearing manager** must advise the **Authority** that it considers that the **event of default** has been remedied.
- (5) *[Revoked]*

Reference number: 089-010

...

Changes to Part 15

...

15.5A Dispatchable load purchaser must prepare dispatchable load information

- (1) Each **dispatchable load purchaser** must prepare **dispatchable load information** using volume information prepared in accordance with Schedule 15.2.
- (2) ~~Unless~~ If clause 15.5B applies to a **dispatch-capable load station's metering installation**, ~~in preparing dispatchable load information,~~ the **dispatchable load purchaser** responsible for the **dispatch-capable load station** must comply with clause 15.5B in relation to the dispatch-capable load station ~~use volume information prepared under Schedule 15.2.~~

Reference number: 064-046

15.5B Deriving volume information if metering installation is within premises that are connected to a point of connection

- (1) This clause applies if a **dispatch-capable load station's metering installation** is not at a **point of connection** but is located within premises that are directly **connected** to a **point of connection**.
- (2) If this clause applies, the **dispatchable load purchaser** responsible for the dispatch-capable load station must prepare **dispatchable load information** using **volume information** prepared in accordance with Schedule 15.2 and derived from the raw meter data—

Reference number: 064-046

...

15.33 The Authority publishes reports

By ~~0930-1630~~ hours on the 2nd **business day** following the day on which the **Authority** receives the report of the **reconciliation manager** in accordance with clause 15.30, the **Authority** must **publish** the sections of the report that relate to an alleged breach of this Code by the **reconciliation manager** (if any).

Reference number: 069-017

...

15.36 New Zealand Daylight Time adjustment techniques

- (1) **Submission information** provided to, and **reconciliation information** provided by, the **reconciliation manager** must, if applicable, be adjusted for **NZDT** using the technique set out in subclause (3) specified by the **Authority**.
- (2) Any information exchanged between **participants** that contains **trading period** specific data must, if applicable, be adjusted for **NZDT** in accordance with subclause (3).
- (3) ~~A~~ Daylight savings adjustments must be made by using ~~1 of the following techniques:~~
 - (a) ~~the “trading period run on technique”, must be applied if the in which requires that~~ daylight saving adjustment periods are allocated as consecutive **trading periods** within the relevant day, in the sequence that they occur. ~~The code “TPR” must be used within the data transfer file when this technique is used.:~~

- (b) ~~the “trading period move technique” must be applied if the daylight saving adjustment periods are appended as additional trading periods at the end of the relevant day. The code “TPM” must be used within the data transfer file when this technique is used.~~
- (4) If no adjustment is made in accordance with subclause (3) to information exchanged between reconciliation participants that contains trading period specific data, the code “NZST” must be used within the data transfer file.

Reference number: 070-018

15.37 Audits

- (1) The **Authority** may, under clause 12 of Schedule 15.1, require a **participant** to have an **audit** undertaken. ~~An **audit** to be undertaken in accordance with this Code must be undertaken by an **auditor** included in the list of approved **auditors** published by the **Authority** in accordance with clause 9(7) of Schedule 15.1.~~
- ~~(2) The **Authority** may require a **participant** to have an **audit** undertaken.~~
- (3) Clauses 12A to 19 of Schedule 15.1 apply to every such **audit**.

Reference number: 017A-038

...

15.38 Functions requiring certification

- (1) A **reconciliation participant** (except an **embedded generator** selling electricity directly to another **reconciliation participant**) must obtain and maintain **certification** in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:
- ...
- ~~(d) calculation of the number of **ICP days** and delivery of a report under clause 15.6:~~
- ~~(da) delivery of **electricity supplied** information under clause 15.7:~~
- ~~(db) delivery of information from **retailer** and **direct purchaser half hourly** metered **ICPs** under clause 15.8:~~
- (d) delivery of:
- (i) a report under clause 15.6 and the calculation of the number of **ICP days** detailed in the report:
- (ii) **electricity supplied** information under clause 15.7:
- (iii) information from **retailer** and **direct purchaser half hourly** metered **ICPs** under clause 15.8:
- (e) ...
- (f) provision of **metering information** to the ~~**pricing manager**~~ **grid owner** in accordance with subpart 4 of Part 13.

Reference number: 096-048

Reference number: 095-047

...

15.38 Functions requiring certification

- (1) A **reconciliation participant** (except an **embedded generator** selling **electricity** directly to another **reconciliation participant**) must obtain and maintain **certification** in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:
- (a) maintaining **registry** information and performing **customer** or and **embedded generator** switching (except if the maintenance of **registry** information is carried out by a **distributor** in accordance with Part 11);
 - (b) gathering and storing **raw meter data**;
 - (c) creating and managing (including validating, estimating, storing, correcting and archiving)—
 - (i) **half hour volume information**; or
 - (ii) non **half hour volume information**; or
 - (iii) **half hour** and non **half hour volume information**; or
 - (iv) **dispatchable load information**;
 - (d) calculation of the number of **ICP days** and delivery of a report under clause 15.6;
 - (da) delivery of **electricity supplied** information under clause 15.7;
 - (db) delivery of information from **retailer** and **direct purchaser half hourly** metered **ICPs** under clause 15.8;
 - (e) provision of **submission information** for reconciliation;
 - (f) provision of **metering information** to the **pricing manager** in accordance with subpart 4 of Part 13.
- (1A) A **dispatchable load purchaser** must obtain and maintain **certification** in accordance with Schedule 15.1 in order to be permitted to perform, or to have performed by way of an agent or agents, any of the following functions in compliance with this Code:
- (a) gathering and storing **raw meter data**;
 - (b) creating and managing (including validating, estimating, storing, correcting, and archiving)—
 - (i) **half hour volume information**; or
 - (ii) non **half hour volume information**; or
 - (iii) **half hour** and non **half hour volume information**; or
 - (iv) **dispatchable load information**;
 - (c) providing **dispatchable load information**.
- ~~(2) To avoid doubt, the performance of any of the functions in subclause (1) by a **reconciliation participant**, or its agent or agents, without the **reconciliation participant** having **certification**, is a breach of this Code by the **reconciliation participant**.~~
- (3) Despite subclause (1), a **reconciliation participant** does not breach this clause by performing a function specified in subclause (1) without having obtained **certification** if the **reconciliation participant** performs the function during the period that is 3 months after the date on which it first performed a function specified in subclause (1).

Reference number: 071-019

...

Schedule 15.1

...

2 Requirement for certification

Despite anything else in this Code, a ~~reconciliation participant~~ who is required to obtain ~~certification~~ under clause 15.38 must obtain ~~certification~~ in accordance with this Schedule no later than 3 calendar months after the date on which that ~~reconciliation participant~~ becomes a ~~reconciliation participant~~ in accordance with this Code.

Reference number: 071-019

...

6 Lists of certified reconciliation participants and agents

The Authority must publish, and keep updated—

- (a) a list of ~~certified reconciliation participants~~, that includes, for each ~~reconciliation participant~~, the date on which the ~~certification~~ expires, and the period for which each ~~reconciliation participant~~ is ~~certified~~; and
- (b) a list of agents used by ~~certified reconciliation participants~~.

Reference number: 072-020

12A Auditor for audits

An ~~audit~~ must be undertaken by—

- (a) the Authority; or
- (b) an auditor included in the list of approved auditors published by the Authority under clause 9(7) as being approved for the type of audit required under clause 12.

Reference number: 017A-038

...

Schedule 15.2

3 Source of volume information

...

- (5) A reconciliation participant must ensure that all raw meter data used to derive volume information in accordance with this Schedule is used to the number of decimal places recorded by each meter, and is not rounded or truncated from the raw meter data provided by the meter.

Reference number: 074-021

...

~~14 Quantification error~~

~~The design of the interrogation system must ensure that the requirements of clause 38(1) of Schedule 10.7 are complied with.~~

Reference number: 074-021

...

Schedule 15.3

...

9 Rounding of submission information

If submission information aggregated by a reconciliation participant under clause 8 is specified to more than 2 decimal places, the A-reconciliation participant must round the submission information—

- (a) to 2 decimal places; and
- (b) so that if the digit to the right of the second decimal place is greater than or equal to 5, the second digit is rounded up, and if the digit to the right of the second decimal place is less than 5, the second digit is unchanged.

Reference number: 076-049